In the Supreme Court of the United States

October Term, 1975

No. 75-1289

The California Company,
A Division of Chevron Oil Company,
Petitioner,

vs.

Federal Power Commission,
Respondent.

Appendix to Petition for a Writ of Certiorari to the United States Court of Appeals for the Fifth Circuit

SORG PRINTING COMPANY OF CALIFORNIA, 346 FIRST STREET, SAN FRANCISCO 94105

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APPENDIX A

OPINION OF UNITED STATES COURT OF APPEALS FOR THE FIFTH CIRCUIT IN SHELL OIL COMPANY V. FEDERAL POWER COMMISSION (NATIONAL RATE CASES FOR NEW GAS), 520 F.2d 1061, DECIDED OCTOBER 14, 1975

[1061]*

*Bracketed numbers indicate pages in 520 F.2d.

SHELL OIL COMPANY et al., Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent, and consolidated cases.*

In re NATIONAL RATE CASES FOR NEW GAS

Nos. 74-3330, 74-4036, 74-4040, 74-4044, 74-4038, 74-4042, 74-4147, 75-1396, 74-4233, 75-1123, 75-1164, 75-1246, 75-1266, 75-1268, 75-1270, 75-1614, 75-1620, 75-1615, 75-1617, 75-1616, 75-1618, 75-1619, 75-1621 to 75-1623, 75-1499, 75-1500, 75-1590, 75-1756.

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*In which the Federal Power Commission is Respondent and the following are Petitioners:

Rodman Corp., 74-4036, 4040, 4044, 4038, 4042; Texas Eastern Transmission Corp. and Transwestern Pipeline Co., 74-4147, 75-1396; General American Oil Co. of Texas, 74-4233; Continental Oil Co., 75-1123; Superior Oil Co., 75-1164; Placid Oil Co. and Hunt Oil Co., 75-1246; Inexco Oil Co., 75-1266; Texas Production Co., 75-1268; Freeport Minerals Co., 75-1270; Associated Gas Distributors, 75-1614, 1620; James Abourezk, 75-1615, 1617; American Public Gas Association, 75-1616; Public Service Commission of New York, 75-1618; Gulf Oil Corp., 75-1619; Sohio Petroleum Co., 75-1621; Amoco Production Co., 75-1622; United Distribution Companies, 75-1623; Kerr-McGee Corp., 75-1499; Phillips Petroleum Co., 75-1500; Exxon Corp., 75-1590; and Texaco, Inc., 75-1756.

United States Court of Appeals,
Fifth Circuit.

October 14, 1975.

[1064]

Petitions for Review of Orders of the Federal Power Commission.

Before BELL, CLARK and RONEY, Circuit Judges.

RONEY, Circuit Judge:

On this review of consolidated cases entitled *National Rate Cases For New Gas,* we sustain the Federal Power Commission's establishment of a national rate for jurisdictional wellhead sales of natural gas.[1] In so doing, for the first [1065] time in this Circuit, we give judicial imprimatur to the promulgation of a rate order through rulemaking procedures in contrast to formal adjudicatory procedures; we sustain a *national* rate for wellhead sales of natural gas in contrast to the *individual producer* rates and the *area* rates that have heretofore been approved; and we hold that the rate structure prescribed withstands various attacks of the producer, purchaser and consumer petitioners against diverse findings and conclusions of the Commission. In sum, we hold the petitioners have failed to show

1. Under review here are a series of orders of the Federal Power Commission issued in The National Rate Proceeding, Docket No. R-389-B; Opinion No. 699 issued on June 21, 1974; Opinion No. 699-A, issued on August 2, 1974; Opinion No. 699-B, issued on September 9, 1974; Opinion No. 699-F, issued on November 7, 1974; Opinion No. 699-H, issued on December 4, 1974; and Opinion No. 699-I, issued January 7, 1975.

The substantive issues in this proceeding have not previously been before this Court. However, on February 20, 1975, the Court issued an opinion and order determining that it had jurisdiction to review these orders and consolidating the various review petitions under the title *National Rate Cases For New Gas* under Docket No. 74-3330, *Shell Oil Co. v. FPC*, 509 F.2d 176 (5th Cir. 1975).

either that the rate structure is unjust and unreasonable, under the limited judicial review permitted this Court, or that the Commission proceeded in disharmony with statutory and judicial requirements.

FACTUAL BACKGROUND

The history of producer regulation under the Natural Gas Act has often been recounted in judicial opinions, necessitating here only a brief statement of the historical background of this national rate proceeding.[2] From 1938 when Congress passed the Natural Gas Act, 15 U.S.C.A. § 717 *et seq.,* until 1954, the Federal Power Commission eschewed regulation of the price paid to the producer at the wellhead for natural gas. The Commission viewed its jurisdiction as limited to regulation of the pipelines which transported and sold natural gas in interstate commerce. The number of companies which the Commission regulated was fairly small. The regulation of the pipelines lent itself to the traditional cost-of-service mode of utility regulation on an individual producer basis.

In 1954 the Supreme Court ruled that the FPC was required to regulate wellhead sales of natural gas by independent producers, defining such producers as "natural gas compan[ies]" within the meaning of § 2(6) of the Act, 15 U.S.C.A. § 717a(6). *Phillips Petroleum Co. v. Wisconsin,* 347 U.S. 672, 74 S.Ct. 794, 98 L.Ed. 1035 (1954). Independent producers are those producers which do "not engage in the interstate transmission of gas from the

2. *See, e. g., Mobil Oil Corp. v. FPC,* 417 U.S. 283, 300-310, 94 S.Ct. 2328, 41 L.Ed.2d 72 (1974); *Permian Basin Area Rate Cases,* 390 U.S. 747, 755-766, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968) [Permian]; *Southern Louisiana Area Rate Cases,* 428 F.2d 407, 415-421 (5th Cir.), *on reh.,* 444 F.2d 125 (5th Cir.), *cert. denied,* 400 U.S. 950, 91 S.Ct. 243, 27 L.Ed.2d 257 (1970).

producing fields to consumer markets and [are] not affiliated with any interstate natural-gas pipeline company." *Phillips* at 675, 74 S.Ct. at 795. The jurisdiction recognized by *Phillips* increased the number of Commission-regulated entities by over thirty-three hundred.[3] This increase in regulatees made the burden of individual regulation unfeasible and forced the Commission to seek an alternative method. Area rate regulation resulted.

The Commission instituted proceedings to regulate the wellhead prices charged by independent producers for certain geographical areas throughout the United States. The Supreme Court held this to be permissible under the Natural Gas Act in its landmark area rate regulation decision, *Permian Basin Area Rate Cases*, 390 U.S. 747, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968). The guidelines set forth in that case have since been used by all Courts of Appeals called upon to review Commission area rate orders. *See, e. g., Southern Louisiana Area Rate Cases*, 428 F.2d 407 (5th Cir.), *on reh.*, 444 F.2d 125 (5th Cir.), *cert. denied*, 400 U.S. 950, 91 S.Ct. 243, 27 L.Ed.2d 257 (1970) [So.La. I].

[1066] The Commission eventually delineated seven geographical areas and established ceiling prices for natural gas sold from those areas by independent producers.[4] Pipeline producers and pipeline affiliated producers were subject to

3. See *Permian*, 390 U.S. at 757 n. 12, 88 S.Ct. 1344.

4. The existence of these geographical areas was noted by the Supreme Court, in a footnote in its most recent area rate review, *Mobil Oil Corp. v. FPC*, 417 U.S. 283, 289-290 n. 3, 94 S.Ct. 2328, 41 L.Ed.2d 72 (1974), which footnote when updated shows the status of the rate proceedings for the various areas as follows:

1. *Permian Basin Area*

Opinion Nos. 468 and 468-A, 34 FPC 159 and 1068, respectively (1965), *aff'd, Permian Basin Area Rate Cases*, 390 U.S. 747, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968).

New rates for this area were established in:

different rate regulation. The Commission has now decided that what it once hoped would be the mainstay of producer rate regulation, the area rate structure, is not the panacea it had sought. Consequently, in this case we are asked to review the next experimental phase in producer regulation, a *national* rate for new natural gas.

Opinion Nos. 662 and 662-A, 50 FPC 390 (1973) (petition for review withdrawn).

2. *Southern Louisiana Area*

Opinion Nos. 546 and 546-A, 40 FPC 530 and 41 FPC 301, respectively (1968), *aff'd, Southern Louisiana Area Rate Cases*, 428 F.2d 407 (5th Cir.), *on reh.*, 444 F.2d 125 (5th Cir.), *cert. denied*, 400 U.S. 950, 91 S.Ct. 243, 27 L.Ed.2d 257 (1970).

New rates for this area were established in:

Opinion Nos. 598 and 598-A, 46 FPC 86 and 633, respectively (1971), *aff'd, Placid Oil Co. v. FPC*, 483 F.2d 880 (5th Cir. 1973), *aff'd sub nom., Mobil Oil Corp. v. FPC*, 417 U.S. 283, 94 S.Ct. 2328, 41 L.Ed.2d 72 (1974).

3. *Texas Gulf Coast Area*

Opinion Nos. 595 and 595-A, 45 FPC 674 and 46 FPC 827, respectively (1971), *rev'd and remanded, Public Service Commission v. FPC*, 159 U.S.App.D.C. 172, 487 F.2d 1043 (1973), *vacated and remanded sub nom., Shell Oil Co. v. Public Service Commission*, 417 U.S. 964, 94 S.Ct. 3166, 41 L.Ed.2d 1136 (1974).

4. *Hugoton-Anadarko Area*

Opinion No. 586, 44 FPC 761 (1970), *aff'd, Hugoton-Anadarko Area Rate Case*, 466 F.2d 974 (9th Cir. 1972).

5. *Other Southwest Area*

Opinion Nos. 607 and 607-A, 46 FPC 900 and 47 FPC 99, respectively (1971), *aff'd, Other Southwest Area Rate Case* (OSWAI), 484 F.2d 469 (5th Cir. 1973), *cert. denied*, 417 U.S. 973, 94 S.Ct. 3180, 41 L.Ed.2d 1144 (1974).

6. *Appalachian and Illinois Basin*

Order Nos. 411, 411-A and 411-B, 44 FPC 1112, 1334 and 1487, respectively (1970) (no appeal).

The Commission declined to establish new area rates for this area in Opinion No. 639, 48 FPC 1299 (1972), *aff'd, Shell Oil Co. v. FPC*, 491 F.2d 82 (5th Cir. 1974).

7. *Rocky Mountain Area*

Opinion Nos. 658 and 658-A, 49 FPC 924 and — FPC —, respectively (1973) (petition for review withdrawn).

STRUCTURE OF THE NATIONAL RATE FOR NEW GAS

Despite protestations from many producers and pipelines, the Commission adhered to *cost* as the basis for the new national rate. The FPC utilized the methodology developed by it in *Area Rate Proceeding* (*Permian Basin*), 34 FPC 159 (1965), *aff'd, Permian Basin Area Rate Cases,* 390 U.S. 747, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968), as modified in the second Southern Louisiana proceeding, *Area Rate Proceeding (Southern Louisiana)*, 46 FPC 86 (1971), *aff'd, Placid Oil Co. v. FPC,* 483 F.2d 880 (5th Cir. 1973), *aff'd sub nom., Mobil Oil Corp. v. FPC,* 417 U.S. 283, 94 S.Ct. 2328, 41 L.Ed.2d 72 (1974) [So.La. II]. Basically the rate was determined by projecting the average cost of finding and producing "new gas," *i. e.,* gas discovered after January 1, 1973, over the estimated life of the producing wells and adding a 15 percent annual rate of return. Historical items of cost were predicted for the future to attempt to insure that the producer would recover its actual expenses at the time work is done. Relating these estimated costs to the commonly accepted unit of gas sold to the consumer results in a maximum allowable rate for natural gas in cents per Mcf, *i. e.,* thousand cubic feet.

Although the rate determined in this proceeding was based on the cost of finding nonassociated natural gas, *i. e.,* gas occurring independently from other extractable forms of petroleum, casing-head gas is also eligible for the new rate, even though it might cost less to pro- [1067] duce. The Commission has long refused to compute separately the cost of casing-head gas because of the difficulty in allocating the production costs between such gas and the oil produced from the same well. *See, e. g., Permian,* 390 U.S. at 761, 88 S.Ct. 1344. Likewise, this national rate will, under certain

conditions, apply to substantially increase the price of "old" gas as well, even though the cost of such pre-January 1973 gas did not figure in the computation of the national rate.

While sales of pipeline producers previously had been vintaged by the date when the natural gas lease was acquired by the pipeline, the Commission decided in Opinion No. 699-H to allow pipeline producers to be eligible for the new rate on the same basis as independent producers. The Commission saw no reason to treat wells commenced by a pipeline any differently than those commenced by independent producers for costing purposes.

In arriving at an ultimate rate figure under this method, the Commission was required to resolve many disputed issues of "pure" fact, assign values to rate components based on a combination of fact and policy considerations, and make policy decisions regarding which components to include, where to include them, and how they should be included. Thus, while the final result is a figure which must have some mathematical relationship to these various considerations, the premises from which the figure is derived are far from mathematically exact. Because of this elasticity in the rate equation, courts traditionally refuse to be drawn into choosing "numbers" which actually represent policy choices properly available to the Commission, the governmental unit to which Congress has primarily committed the regulation of the natural gas industry.

The Commission developed both a "high" and a "low" cost figure by making various choices among the alternatives available to it. The overall cost determination was based on an evaluation of the following components: (1) Successful Well Cost, (2) Dry Hole Cost, (3) Lease Acquisition Cost, (4) Cost of Other Production Facilities, (5) Other Exploration Cost, (6) Exploration Overhead, (7) Produc-

tion Operating Expense, (8) Net Liquid Credit (subtracted from costs), (9) Royalty Expense, (10) Recompletion and Deeper Drilling Cost stipulated, (11) Regulatory Expense (stipulated), (12) Return on Production Investment, and (13) Return on Working Capital. The Commission did not include an element of cost for federal income tax but established a procedure whereby a producer can gain an increase for taxes paid upon jurisdictional activities by making an individual showing that such expense was actually incurred.

Various of these cost components have been attacked on appeal and will be discussed more fully hereinafter, but first a brief description of the FPC methodology may be helpful.

Like every cost factor, *Successful Well Cost* must be converted to cents per thousand cubic feet, the base unit. Ideally, to do this the Commission would divide the number of feet drilled in a given year which resulted in finding nonassociated natural gas into the nonassociated natural gas reserves discovered as a result of such drilling. The quotient is called the "productivity" of the drilling and is expressed in Mcf of newly-discovered gas per foot of drilling (Mcf/ft). The cost of drilling a foot of a successful well (¢/ft) would then be divided by the productivity (Mcf/ft) with the quotient being expressed in the desired unit, cents per thousand cubic feet (¢/Mcf). This computation is not feasible as described, however, because of the manner in which data concerning the natural gas industry is collected. Drilling footage is recorded in the year it occurs, but no one compiles reserve additions by wells drilled. Instead, "reserves added" are computed on a net annual basis, taking into account reductions in reserves which have been previously overestimated. Thus, there are variables other than successful well drilling which affect the net nonassociated

reserve additions for a giv- [1068] en year. Nonetheless, the FPC must compute productivity, so it used the only information available to it for reserve additions, the American Gas Association reserve studies and the various footage compilations.

Dry Hole Cost (cost of drilling unsuccessful wells) was separately computed by dividing the cost per foot drilled (¢/ft) by the productivity of successful wells (expressed in Mcf/ft), computed as previously discussed, with the quotient again being in cents per thousand cubic feet (¢/Mcf). The figure so obtained was then adjusted upward to reflect the greater depth and thus higher costs and the offset of higher success ratio at those depths for gas well drilling as compared to oil well drilling.

Lease Acquisition Cost, expressed in dollars, was reduced to the base unit, ¢/Mcf, by determining the relationship between total Successful Well Cost and total Lease Acquisition Cost in a given year. The ratio of the former cost to the latter cost was then multiplied by the previously determined Successful Well Cost per unit, the result being Lease Acquisition Cost per Mcf.

Cost of Other Production Facilities is the cost of those production facilities not included in Successful Well Cost. To convert this cost to the base unit, the Commission divided total Other Production Facilities Cost by total Successful Well Cost and multiplied the unit Successful Well Cost by the resultant ratio.

Several elements were used in computing *Other Exploration Cost*: the unit Lease Acquisition Cost component (expressed in ¢/Mcf) was multiplied by the ratio of total national Other Exploration Cost to total Lease Acquisition Cost. Other Exploration Costs are the direct costs, other than the cost of drilling a dry hole, which are experienced

in the search for natural gas. These should be distinguished from the Exploration Overhead, which was separately computed as a component of the rate structure.

Exploration Overhead was derived by multiplying the sum of unit Dry Hole Cost and Other Exploration Cost by the ratio of National Exploration Overhead Cost divided by National Other Exploration Cost, using a multi-year average.

Production Operating Expense, the daily costs of labor, energy, and other expenses for operating a successful well, was calculated by dividing operating expenses for gas leases by the production from gas leases (expressed in Mcf) to obtain a unit value quotient.

Net Liquid Credit, unlike the other components of the cost based rate, represents receipt of revenue incident to the production of natural gas, and, therefore, is a credit against expenses. In processing natural gas, certain liquifiable hydrocarbons, such as propane, butane and ethane are extracted and liquified. These liquids are then sold and the experienced revenue from these per Mcf of natural gas was subtracted as the Net Liquid Credit.

Royalty Expense represents the percentage of the gross receipts which a producer must pay to the landowner for the privilege of extracting from the reserves underlying his land. It was computed by applying a percentage to the gross receipts.

Two cost components were stipulated by the parties, which stipulations were accepted by the Commission as representative costs: Recompletion and Deeper Drilling Cost and Regulatory Expense. *Recompletion and Deeper Drilling Costs* are incurred in rejuvenating old wells to extend their productive life. *Regulatory Expense* is the cost per Mcf which is directly attributable to the cost of filing

required reports, of participating in proceedings such as the instant one, and of other necessary activities related to both state and federal regulation.

Return on Production Investment and Return on Working Capital were computed by applying the annual rate of return decided upon to certain predicted costs.

Certain of the cost items are included in the "rate base" upon which the Com- [1069] mission allows the producers to receive a percentage return on expenses, some are not. The decision as to which items are properly part of the rate base for return purposes is one which involves policy as well as economic considerations. The items which are not included in the rate base are still recoverable as expenses. The cost components comprising the rate base, and, therefore, on which a rate of return is allowed are Successful Wells, Dry Holes, Lease Acquisition, Other Production Facilities, Other Exploration, Exploration Overhead, and Recompletion and Deeper Drilling. The remaining items, Production Operating Expense, Net Liquid Credit, Royalty Expense, and Regulatory Expense, are treated as annual credits or expenses. Having decided on which items a return would be allowed, the Commission computed the unit cost of that return at a 15 percent annual rate using a discounted cash flow economic model.

In computing all costs to be used in the above-described model, the FPC recognized that it could not be exact and, therefore, made a number of different assumptions regarding each component. In this manner the Commission arrived at the range of what it considered reasonable costs, with a "low" total cost based primarily on the low assumptions and a "high" total cost based primarily on the higher assumptions. For example, in computing drilling costs for the 1973-74 time period for which the rate was designed,

the "low" cost was actual experienced cost in 1972, whereas, the "high" cost was the 1972 cost projected by the least squares regression method in order to account for a rising trend in drilling costs. Similarly, the important element, productivity, was computed to produce a high and a low estimate: as productivity has been declining recently, a longer period (10 years) was averaged to produce the "low" cost than was averaged to produce the "high" cost (7 years). The Commission asserts that it set the 15 percent annual rate of return high enough above a traditionally non-confiscatory rate of return to put some noncost factors into the rate to make the interstate market more competitive with other markets.

Ultimately, the FPC determined that a reasonable rate could fall between 48 cents and 52 cents, based on all factors. From this range the Commission chose 50 cents per Mcf as the rate it would allow on jurisdictional natural gas subject to the No. 699 series of opinions.

A. *Ancillary Provisions in the Rate Structure*

Besides a determination of the rate and the natural gas to which it would apply, the Commission's order contains a number of ancillary provisions, some of which are important to an understanding of the rate structure.

First, the order made provision for special relief in unusual circumstances where the rate is not sufficient to recover the cost of producing natural gas already dedicated to the interstate market. The burden is on the producer with the above average costs to justify an additional price for its gas. This is not the only avenue of extraordinary relief for producers who may be adversely affected by the national rate structure, however. The FPC has standing regulations which afford relief to producers who face an increase in

costs. 18 C.F.R. § 2.76 (1974). A producer who is seeking special relief because of federal income taxes actually paid may use procedures established in this proceeding for such relief. Thus, although federal income taxes are not allowed as a cost in the basic "cost-based" rate, they are recoverable, if actually paid, by use of a special relief proceeding.

Second, the rate structure provides for a biennial review of the rate and the rate's efficacy in accomplishing the goals which the FPC is seeking to attain. It is the Commission's stated policy that any increased rate found just and reasonable in each biennial review will be allowed for all natural gas which is subject to the present proceeding.

Third, the rate structure provides for a fixed annual rate escalation, irrespective of any additional proof of increased [1070] costs. Under this provision gas subject to this proceeding is allowed a one-cent per Mcf escalation in price as of January 1 of each year.

B. *Scope of the Order*

Besides the requirement that the natural gas be produced within the continental United States, or offshore thereof, exclusive of Alaska, the current scope of the order is primarily defined by the interaction of three possible occurrences relating to natural gas distribution and production. If any one of them occurred on or after January 1, 1973, the sales of natural gas from the affected well are eligible for the new national rate under the Commission's regulations. The three sale situations which justify the new rate were described by the Commission in Opinion No. 699-H:

(i) The sale is made from a well or wells commenced on or after January 1, 1973;

(ii) Sales made pursuant to contracts for the sale of natural gas in interstate commerce for gas not

previously sold in interstate commerce prior to January 1, 1973, except pursuant to the provisions of 18 C.F.R. §§ 2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission Order No. 491, et al.) [temporary emergency sales of various sorts], or 18 C.F.R. § 2.75(n), where such sales are initiated on or after January 1, 1973, provided that no certificate for the subject sale has been issued under the optional procedure (18 C.F.R. § 2.75);

(iii) Sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

The propriety of applying the new rate to sales made under (i), the "wells commenced" standard, and (ii), new long-term commitments of natural gas to interstate commerce is not questioned in this proceeding.

The application of the new rate to category (iii), sales made pursuant to renewal contracts of natural gas previously committed to interstate commerce, is challenged on this review as unjustifiable.

STANDARD OF REVIEW

It is always necessary to keep in mind the limits of judicial inquiry when we are called upon to review an order

issued by the Federal Power Commission. Although these limits have been variously explicated over the years, they have never been diverted from the "end result" test which finds its genesis in the earliest Supreme Court cases reviewing orders under the Natural Gas Act. *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1944); *FPC v. Natural Gas Pipeline Co. of America*, 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037 (1942). The end result test was tailored to area rate orders by the Supreme Court in *Permian Basin Area Rate Cases*, 390 U.S. 747, 766-767, 791-792, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968). This Court has, on various occasions, discussed our understanding of the *Permian* prescription. *See Shell Oil Co. v. FPC*, 491 F.2d 82, 85 (5th Cir. 1974); *Placid Oil Co. v. FPC*, 483 F.2d 880, 888-890 (5th Cir. 1973), *aff'd sub nom., Mobil Oil Corp. v. FPC*, 417 U.S. 283, 94 S.Ct. 2328, 41 L.Ed.2d 72 (1974); *Southern Louisiana Area Rate Cases*, 428 F.2d 407, 417-418 (5th Cir.), *on reh.* 444 F.2d 125 (5th Cir.), *cert. denied*, 400 U.S. 950, 91 S.Ct. 243, 27 L.Ed.2d 257 (1970).

[1] The issue which we must ultimately resolve is whether the end result [1071] of the order is "unjust and unreasonable." In assessing the facts from which this ultimate conclusion is derived, we are guided by four elements which delimit the scope of our authority:

(i) the well-known statutory "substantial evidence" standard, (ii) a judicially recognized "presumption of validity" implied from the congressional limitation, (iii) the long-standing "total effect" test of *FPC v. Hope Natural Gas Co.*, 1944, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333, and (iv) a "zone of reasonableness" to compensate for the necessarily imprecise nature of cost determinations and the inherent difficulty of the regulatory undertaking.

Placid Oil Co. v. FPC, supra at 889 n. 6.

The fact that our vision is tunneled does not relieve us, however, from our duty to look at the Commission order from all angles. The Supreme Court has made clear

> . . . that the responsibilities of a reviewing court are essentially three. First, it must determine whether the Commission's order, viewed in light of the relevant facts and of the Commission's broad regulatory duties, abused or exceeded its authority. Second, the court must examine the manner in which the Commission has employed the methods of regulation which it has itself selected, and must decide whether each of the order's essential elements is supported by substantial evidence. Third, the court must determine whether the order may reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable. *The court's responsibility is not to supplant the Commission's balance of these interests with one more nearly to its liking, but instead to assure itself that the Commission has given reasoned consideration to each of the pertinent factors.*

Permian Basin Area Rate Cases, supra at 791-792, 88 S.Ct. at 1373 (emphasis supplied).

In the review of area rate cases, however, our already narrow scope of review has been tempered even further by recognition of the experimental nature of area regulation. *E. g., Placid Oil Co. v. FPC, supra* at 889-890; *Southern Louisiana Area Rate Cases, supra* at 418; *see Permian Basin Area Rate Cases, supra passim.* The "kid glove"

review resulting from the "experiment rationale" has led this Court and the Supreme Court to accept findings and reasoning by the Commission as adequate, even though both courts have expressed serious misgivings about the ultimate accuracy of the FPC's conclusions. Accordingly, on at least two occasions we have "affirmed" or "enforced" FPC orders while expressing our concern about the marginal adequacy of the FPC orders. We have specifically reserved to the Commission the authority to make retroactive changes to the very orders we "affirmed" as being supported by substantial evidence. *Southern Louisiana Area Rate Cases, supra* at 421, 426 n. 46, 427, 431, 434-444; 444 F.2d at 126-127. *See Shell Oil Co. v. FPC, supra* at 87-88. The FPC responded to our admonition with a more extensive study of the problem in the Southern Louisiana Area, and the resultant area rate order was affirmed by both this Court and the Supreme Court. *Placid Oil Co. v. FPC,* 483 F.2d 880 (5th Cir. 1973), *aff'd sub nom., Mobil Oil Corp. v. FPC,* 417 U.S. 283, 94 S.Ct. 2328, 41 L.Ed.2d 72 (1974).

[2] To affirm the action of the Commission on review here requires continuation of the heightened deference to the Commission's expertise inherent in the "experiment doctrine." Opinions 699 and 699-H assert many factual conclusions and regulatory justifications without explicating for this Court the factual predicates or assumptions upon which such decisions are based. We have concluded, however, that national rate regulation is still experimental and we must [1072] apply a standard of review requiring heightened deference to the Commission's expertise in such experimental regulations.

The first area rate regulation proceedings related to the Permian Basin Area and began in 1960. Prior to the establishment of the national rate in this proceeding, the FPC

had considered area rate structures in ten proceedings involving seven distinct geographical areas. Seven of these proceedings were the subject of judicial review and comment, with two of those receiving review by both a court of appeals and the Supreme Court.[5] An examination of the area rate structures and the cases in which they were reviewed reveals that the FPC has continued to experiment with various combinations of contingent escalations, automatic escalation, vintaging, refund workoffs and the like in an attempt to alleviate the national natural gas shortage by stimulating exploration and development. At the same time the Commission has persisted, in spite of the protestations of the producers, in relying upon a cost-based rate as the starting point in an effort to protect the consumer from exploitation in this time of shortage.

The national rate structure under review is a unique combination of provisions which, along with the shift to a national rate itself, demonstrates that the Commission does not believe that any of the total rate structures which it developed in the area proceedings had the desired effect of providing developmental incentive while preventing exploitation. The Commission has been unsuccessful in generating additional natural gas reserves for the interstate market within the framework of its congressional mandate. In the face of growing demand for natural gas by the intrastate market, the effort to protect consumer interest as to price is at odds with the long range consumer interest in maintaining an adequate supply of natural gas for the interstate market. Finding and maintaining this point of delicate balance is a difficult task. Congress has chosen the FPC to be its surrogate for this responsibility, and our view of

5. See footnote 4 *supra*.

the agency's work must take into account the attendant difficulties to assure that the legislative scheme will be effectuated.

We must express our regret, however, that the FPC continues to issue orders which would be inadequate but for our "kid glove" treatment. Perhaps one reason the Commission has continued to flounder in the sea of area regulation is its failure to assess the consequences of its various policies. For example, if it does not have reasonable knowledge of the effect a contingent escalation in price will have, it can hardly evaluate the efficacy of having such a provision in the rate structure. Just as we must consider individual elements in our review of an FPC order to insure that it is supported by substantial evidence, so should the Commission examine the effect of each when it is deciding how to compose the rate structure initially. For over fourteen years the Commission has been experimenting in area rate regulation and yet it still "supports" many of the essential elements of its new national rate order with little more than *ipse dixit.*

We recognize, of course, that the issues in a review such as this are not always separate and distinct, but involve overlapping considerations and resolutions. But a cautionary note should indicate that as experiment lapses into experience, the courts may well expect the Commission to justify its policies with reasoned projections of that once-prototypic policy's probable net effect. The principle of *stare decisis* may only lightly touch the standard of subsequent review.

Therefore, with these principles of review in mind, we give a limited review to the Commission's actions.

[1073]

IS A NATIONAL RATE PERMISSIBLE UNDER THE NATURAL GAS ACT?

[3] The initial inquiry is whether the Commission has the authority to establish a *national rate* under the Natural Gas Act. It would seem clear that under existing Supreme Court cases there is no legal impediment to the Commission's choosing a national rate as its method of regulation of wellhead sales of natural gas. In the approval of area rates, the extent of the area does not appear to have been a controlling consideration. To a large extent, the nation is merely a geographically expanded area. The rate set in at least some of the area rate proceedings was based on national data only. The most noteworthy of the Supreme Court cases in this regard is, of course, *Permian* itself. *See* 390 U.S. at 761, 88 S.Ct. 1344. We think that the Supreme Court's approval of an area rate for new gas based partially on national data requires us to uphold the legality of a national rate in this case.

This decision that such rate regulation is permissible comes with some misgivings. A national rate exacerbates the problems noted in Justice Douglas' dissent from *Permian* as to the rates set for the relatively small geographical area involved in that case.

> The area rate orders challenged here are based on averages. No single producer's actual costs, actual risks, actual returns, are known.
>
> The "result reached" as to any producer is not known.
>
> The "impact of the rate order" on any producer is not known.
>
> The "total effect" of the rate order on a single producer is not known.

Permian Basin Area Rate Cases, 390 U.S. at 829-830, 88 S.Ct. 1344 (Douglas, J., dissenting) (footnote omitted).

The problem with the legality of any area rate, and most particularly a national rate, stems from the fact that the legal role of a reviewing court under the Act involves a bifurcated examination of the "end result" or consequence of any FPC rate order: (1) does the order protect the consumer against excessive rates and charges; and (2) is it consistent with the maintenance of adequate service in the public interest. See generally *Atlantic Refining Co. v. Public Service Commission,* 360 U.S. 378, 388, 79 S.Ct. 1246, 3 L.Ed.2d 1312 (1959). If this is our Court's role, as opposed to merely preventing confiscation, then it is arguable that any rate methodology which inherently prevents this Court from performing its role contravenes the Act. Put another way, if there can simply never be "substantial evidence" to support the discretionary exercise of judgment by the Commission, then it could be argued that the method of regulation should be outside the scope of the Act.

The national rate presents such a circumstance. First, since it is largely "prospective" the rate can hardly be confiscatory because the producers may adjust their programs within the structure of the national rate in such a manner to produce the profit which they need, virtually disregarding the Commission's "reasonable rate of return." In an industry with high risks of exploration and development, prospective rates arguably could never really work "confiscation" in the constitutional sense. If the producers' geological surveys remain reasonably accurate, they will usually be able to produce some quantity of gas at a profit within practically any rate structure. They will simply stay out of high cost production that would earn less profit than necessary to attract venture capital. The larger the rate the

greater would be the exploration for new reserves. The producers here do not assert the invalidity of the rate on the ground that it is confiscatory.

Assuming then, that the rate is not confiscatory, the use of a national rate with biennial review precludes any court from effective review based on the "end result" of the rate order. First, because there is never one definitive, lasting rate determination, the "end result" of Commission action is in a continuous state of flux. Second, the Commission itself [1074] makes no evaluation of the "end result" of its rate order. The Commission concludes that supply and price are directly proportional, *i. e.*, that an increase in the price allowed will result in an increase in supply. From this the Commission reasons that an increase in the price allowed will of necessity do something to alleviate the natural gas shortage which everyone recognizes has developed. But the FPC "found" that there was no way to quantify this relationship and that there is accordingly no way to determine just how much any given price increase will affect the supply of natural gas. There is no reliable estimate as to what new gas will be brought to the interstate market because the Commission reports that such a factually reliable estimate is impossible. Without any such quantification, it is simply impossible for this Court to determine if the "end result" will maintain an "adequate supply in the public interest" or not. Going on past experience for area rates the answer appears to be in the negative, and it is in part for this reason that the FPC has abandoned area rates.

What basically appears to exist, then, is a method of regulation by area, approved by the Supreme Court, at least as an experiment, and a standard of review, similarly prescribed by that Court, which are somewhat incompatible. The method of regulation prevents quantification of the

effects of FPC decisions, with only the most general conclusions readily deducible, whereas, this Court is supposed to examine this unquantifiable "end result" to determine whether the FPC order is acceptable.

Having decided, however, that we are bound to approve a national rate method of regulation control of natural gas, our review of the Commission's actions must be tailored to the practical requirements of the circumstances. Little would be accomplished by on the one hand deciding that a national rate could be established, while on the other hand burdening the Commission with procedural and evidentiary requirements which, though necessary to the legality of individual or smaller area ratemaking, would either prolong or complicate the task of the Commission to the point of impossibility.

DOES RATEMAKING BY THE RULEMAKING PROCEDURE COMPORT WITH STATUTORY REQUIREMENTS AND CONSTITUTIONAL DUE PROCESS?

The American Public Gas Association (APGA) challenges the Commission's use of a rulemaking process to set a national rate for natural gas, arguing that by excluding adversarial trial procedures such as formal evidentiary hearings, oral testimony and oral cross-examination, the Commission violated both the requirements of the Natural Gas Act and those of constitutional due process.

In setting a national rate for new gas the Commission went beyond the rudiments of informal rulemaking. On April 11, 1973, the Commission issued a notice of proposed rulemaking, which clearly indicated that the Commission intended to establish by rule nationwide rates for natural gas. 38 Fed.Reg. 10014 (1973). The notice made all large

producers respondents to the ratemaking proceeding, and provided for the submission of sworn written comments from all interested parties. Shortly thereafter the FPC gave notice that it intended to establish a single national rate for new gas. 38 Fed.Reg. 14295. These Notices of Rulemaking incorporated Commission cost studies. Pursuant to these Notices over eighty parties representing a broad range of consumer and gas industry interests responded, submitting such sworn testimony and evidentiary data as they desired. Parties thereafter submitted reply comments, this second round of submittals giving them an opportunity to rebut both Commission and privately-generated evidence. In addition to accepting copious written responses to its proposed rulemaking, the Commission held a public conference on the issues of reserve additions and drilling footages, and held two days of oral argument on proposed Opinions Nos. 699 and 699-H.

[1075]

In upholding the rulemaking procedures used by the Commission in this proceeding we do not find it necessary to decide what minimum procedures are necessary under the Natural Gas Act and the Administrative Procedure Act. It is unnecessary to enter the colloquy between the Tenth and the District of Columbia Circuits as to whether informal rulemaking (5 U.S.C.A. § 553) or formal evidentiary hearings (5 U.S.C.A. §§ 556, 557) are mandated by the Natural Gas Act. *Compare Phillips Petroleum Co. v. FPC*, 475 F.2d 842 (10th Cir. 1973) (holding that the informal rulemaking provision of the Administrative Procedure Act, 5 U.S.C.A. § 553, applies to FPC rulemaking) *with Mobil Oil Corp. v. FPC*, 157 U.S.App.D.C. 235, 483 F.2d 1238 (1973) (holding that § 553 rulemaking is insufficient, but §§ 556, 557 hearings are not necessarily required by the

Natural Gas Act). But see *American Public Gas Association v. FPC*, 498 F.2d 718 (D.C.1974) (rulemaking to set area rates did not abuse the Natural Gas Act).

[4, 5] The above-described procedural process which is on review before this Court satisfies even the more stringent requirements of the formal hearing process. The APGA is incorrect in arguing that it has a statutory right to present oral testimony or conduct oral cross-examination. The Administrative Procedure Act provides in pertinent part that

> A party is entitled to present his case or defense by oral or documentary evidence, to submit rebuttal evidence, and to conduct such cross-examination as may be required for a full and true disclosure of the facts. In rule making . . . an agency may, when a party will not be prejudiced thereby, adopt procedures for the submission of all or part of the evidence in written form.

5 U.S.C.A. § 556(d). The procedures used in setting the national rate neither prejudiced the APGA, nor prevented a full and true disclosure of the facts. On this appeal petitioner APGA has failed to demonstrate that oral, adjudicatory procedures were necessary for a full and fair disclosure of the facts. All private submissions and Commission cost studies were on record either at the time of the Notices in the case of Commission data or after the first round of submissions, and petitioners had ample opportunity for refutation. Evidence of a technical nature is well suited for written dissection. Without concrete demonstration of how the Commission's reliance on written submittals prejudiced the rights of the petitioners, we cannot say that as a matter of law the FPC was prohibited from adopting the procedures it did, or was required to conduct a full, oral hearing.

As a second line of argument, the APGA contends that even if the rulemaking procedure is statutorily correct, it violates the due process rights of affected parties. Constitutional due process "is flexible and calls for such procedural protections as the particular situation demands." *Morrissey v. Brewer*, 408 U.S. 471, 481, 92 S.Ct. 2593, 33 L.Ed.2d 484 (1972). In FPC ratemaking we agree with the D.C. Circuit that:

> Whatever procedure is utilized, a primary objective is the acquisition of information which will enable the Commission to carry out effectively the provisions of the Natural Gas Act. The ability to choose with relative freedom the procedure it will use to acquire relevant information gives the Commission power to realistically tailor the proceedings to fit the issues before it, the information it needs to illuminate those issues and the manner of presentation which, in its judgment, will bring before it the relevant information in the most efficient manner.

City of Chicago v. FPC, 458 F.2d 731, 743-44 (D.C.Cir. 1971), *cert. denied*, 405 U.S. 1074, 92 S.Ct. 1495, 31 L.Ed.2d 808 (1972). The procedures before us serve the purpose of providing the Commission with essential information, while protecting the procedural rights of concerned parties under the circumstances. Private parties were afforded ample opportunity to make their case and to challenge both internally and externally generated evidence of costs and conditions [1076] which affected the calculus of a national rate for new gas. Were the Commission to have allowed all interested parties to submit oral testimony and conduct oral cross-examination on an undertaking so massive and novel as setting a national rate for new gas, the proceeding would

have taken years, and the Commission's power to effectively regulate the industry would have been destroyed.

The Public Service Commission for the State of New York brings a more limited due process challenge, arguing that insufficient notice was given that the Commission's order would extend to renewal contracts which concern flowing ("old") gas. Under the circumstances, and in light of the necessity to maintain flexible agency procedures, we hold that New York received adequate notice of the enlargement of scope. The Commission's initial Notice of Proposed Rulemaking issued on April 11, 1973, did not indicate that old gas would be affected by the new national rate. Prior to issuance of an FPC order, however, producer groups raised the possibility of extending the order. New York responded to the producer proposals, and, 42 days after the issuance of Opinion No. 699, the FPC granted rehearing of that order, scheduling two days for oral argument, available to any party who wished to participate. Following consideration of both written and oral argument against Opinion No. 699, the FPC issued its final order on rehearing, Opinion No. 699-H. Under these circumstances the Public Service Commission's right to make its case against extending the higher new rate to flowing gas was not prejudiced. It had the opportunity to state its position and refute positions to the contrary prior to the issuance of Opinion No. 699, and thereafter New York had a fair opportunity to argue against the FPC action before the new rate system became final.

REVIEW OF SPECIFIC OBJECTIONS TO NATIONAL RATE

Having concluded that the Commission was within its authority in choosing a national rate structure to regulate

independent producers of natural gas, we now examine the manner in which the FPC has applied its chosen methodology to see that the essential elements of the various orders are supported by substantial evidence or that they otherwise withstand review. While the parties have attacked many different components of the Commission's rate structure, we think only the following merit separate treatment and extended comment. The other issues will be discussed briefly in a miscellaneous portion of this section of the opinion.

A. *Application of New Rate to Renewal Contracts*

[6] The Commission's decision to allow the new national rate to be charged for natural gas sold pursuant to renewal contracts replacing old contracts which had expired by their own terms prior to January 1, 1973, where the sales under the prior contracts were made pursuant to permanent certificates of public convenience and necessity of unlimited duration, has been challenged as unjustified by some producers and consumers. The producers, particularly Superior Oil Company, assert that the requirement that there be a newly executed contract is arbitrary. They reason that since under the Commission's order the delivery of natural gas must continue at the old rate under the certificate, even though there is no private contract, there is no incentive for a pipeline to negotiate and the requirement for a contract is, therefore, anticompetitive. Although the producers can be relieved of this duty to continue deliveries by successful prosecution of an abandonment proceeding, such proceeding is costly both in terms of time, while the lower rate is being received, and in terms of money to prosecute the abandonment.

The consumer interests are represented on this issue by Associated Gas Distributors, New York, and the American

Public Gas Association. These parties basically attack the asserted rationale [1077] for the Commission decision as being unsupportable in the record.

The Commission reasoned that application of the new, higher rate to "old" gas as primary contracts expire will generate added funds for greater exploration. The FPC thus applied the rate functionally to "old" gas rather than on a cost-related basis, hoping that a higher uniform rate will help alleviate the current severe shortage. The FPC believed that by requiring an old contract to be renegotiated before the new rate is recoverable, the pipeline might be able to negotiate for additional acreage dedication to interstate commerce, or exploration and development activity on previously dedicated acreage or other concessions for the price increase. The consumers argue that in this time of an ever-increasing shortfall of supply the pipelines will simply not be in the position to bargain for or gain any *quid pro quo,* and, therefore, the Commission should have *required* some such concession from those producers who are allowed the "windfall" rate increase on "old" gas.

The arguments on each side of this issue have some validity, creating in their juxtaposition a contradiction which buttresses this Court's deferral to the reasoned expertise of the Commission. Our responsibility is not to supplant the Commission's choice with one we might find preferable, but simply to make sure that the Commission has exercised its discretion after considering all pertinent options. The FPC has reached a well-considered, expert decision on this issue. The Commission found from evidence in the record that a massive commitment of new funds is necessary to alleviate the natural gas shortage and that internally generated sums are a necessary source of such funds. Additionally, it noted that by phasing out the vin-

taging practice and attending price variations, all consumers would more equitably bear the burden of financing added exploration. From these facts it reasoned that the national rate structure should be functionally applied to provide some of these funds, placing the burden not just on "new" gas but also on flowing gas for which the primary contract had expired. In so doing the Commission recognized that natural gas is an exhaustible commodity and expressed its belief that today's consumers should share the burden of finding replacement supplies for the supplies which are being exhausted by the consumers.

Furthermore, the Commission does not consider the matter finally determined. It has expressly reserved for consideration in the biennial review the question of whether the pipelines are negotiating in good faith or trying to take advantage of the producer's locked-in position, and whether or not the additional funds generated by the application of the new rate increase "the level of monies committed to exploration and development programs and the volumes of new gas supplies dedicated to interstate pipelines under long-term contracts." Opinion 699-H, Appendix pp. 564-65 and footnote 121. The Commission has thus remained flexible and is prepared to adjust the national rate structure as necessary. The Commission has struck a tentative balance between the consumer and the investor interests and stated that it is prepared to reevaluate the equilibrium it sought to achieve in the biennial review. Under such a circumstance, no party has carried the heavy burden of showing that the Commission's balance is tilted so far in either direction as to be unjust and unreasonable in its consequence. We also consider the decision, although not compelled by the evidence, to be supported by the substantial evidence of a shortage and the need for a massive infusion of funds.

B. *Trend Toward Elimination of Vintaging*

[7] The practical result of allowing flowing or "old" gas to be sold at the new national rate upon expiration or renegotiation of preexisting contracts is that the former "vintaging" of gas according to its period of discovery will gradually disappear. The Commission is not bound by its previous policies. As [1078] this Court and the Supreme Court have noted on various occasions, the rate structures which introduced or adjusted vintaging were experimental. It is necessary without a doubt that agencies be permitted latitude to evaluate old experiments and modify or abandon them when their best judgment requires such a course of action. The Commission's reasons for permitting old gas to be repriced at the new rate apply equally to the related decision to abandon vintaging.

C. *Commission's Productivity Projections*

One of the most important and hard to predict variables in the cost-based formula is productivity, the amount of natural gas that will be added to nonassociated gas reserves for every foot drilled resulting in some addition to those reserves.

The Commission's decision as to predicted productivity is attacked from both sides. Shell, Amoco and the United Distribution Companies assert that the productivity estimates ignored the only substantial evidence in the record which showed a decreasing trend. American Public Gas Association, on the other hand, contends that the productivity is overstated because the Commission did not use the longest term data available, as had been its practice in previous area rate cases. The parties do not really argue that the ultimate productivity projections are not based on substantial evidence, but rather assert that the Commission's analysis of that evidence, and the inferences drawn

therefrom were incorrect. We find, however, that the Commission's resolution of this admittedly difficult and uncertain factual issue is supported by the record.

The record in this case presented two special problems for the Commission in using historical figures to predict future productivity in addition to those previously discussed: first, how to treat the historical rates in light of a recent trend of decreasing productivity, and second, what adjustment to make because of a Staff study which suggested that some reported reserve additions were understated in the only available information source, American Gas Association, American Petroleum Institute, and Canadian Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972, Vol. 27 (1973).

Because lower productivity means that the cost of drilling must be spread over less natural gas, resulting in a higher price per Mcf, the producers urged the Commission to accept the trend as valid and to predict an even lower productivity for the future. In addition the producers pointed out that in this time of shortage more marginal reserves, *i. e.,* those with lower productivity, need to be developed, and this will only occur if the productivity allowance in the national rate justifies such a development. On the other hand, the Associated Gas Distributors urged the Commission to use only the data for 1952-1967, and to ignore the decreasing productivity trend from 1968 as being based on unreliable reserve data.

[8] Faced with these conflicting positions, the Commission made a choice of what evidence to use in predicting productivity over the effective period of its rate order. The FPC adopted a middle ground computing the productivity

for the "high" end of its range of reasonable rates from the most recent seven years (1966-1972) and computing the "low" end from the most recent ten years (1963-1972), making adjustment to the final rate range for the Staff-found understatement of nonassociated reserves. This choice of evidence is itself subject to review by this Court for evidentiary support. *Southern Louisiana Area Rate Cases, supra* at 425 n. 42.

The Commission recognized that the trend of decreasing productivity resulted from the interaction of two factors: drilling footages had dramatically increased in recent years as producers redoubled the search for nonassociated natural gas in the face of the national [1079] shortage, but reserve additions had steadily declined. There is no dispute over the existence of substantial evidence of the facts which demonstrate these two factors. The Commission analyzed these trends to project the likelihood of their continuance.

The FPC reasoned that the steady decline in reserve additions data was adjusted downward for significant net negative revisions to existing nonassociated gas reserves, as estimates for older reservoirs were updated to reflect continuing production experience. There is no way that the reservoir which is negatively adjusted can be isolated by year of discovery so that productivity for that year could be properly adjusted. Instead the productivity for the year in which the discrepancy is discovered is affected. The second factor which the Commission considered important in correctly understanding the reserve addition data was the low level of new field and new reservoir discoveries. The FPC believed this to be abnormally low and a result of decreased leasing in the offshore federal domain in the late 1960's. It anticipated an increase in such discoveries would result from an increase in such leasing.

The Commission acknowledged that it was impossible to isolate the age of the reservoirs which accounted for the negative revisions, but expressed its belief, based on the fact that the revisions were obtained from "continuing production experience," that at least a substantial portion of the large negative revisions related to older reservoirs. The FPC considered such revisions nonrecurring. Considering all of these facts and the inferences it drew from them, the Commission concluded that nonassociated gas reserve additions had been abnormally low in the recent past and anticipated an increase in the near future.

[9] The Commission recognized that drilling footages had increased and could be anticipated to continue increasing as the search for natural gas broadened. In fact, one of the primary goals of the FPC in formulating the national rate in this case was to stimulate exploration and development of new reserves. The Commission concluded, however, that the negative effect on productivity of this increased drilling was likely to be offset by the increased reserve additions it anticipated as developing. Because of this interaction, the Commission considered the productivity trend as unrepresentative of projected productivity and chose instead to rely on averages of past data to compensate for the inaccuracy of the reserve reporting system and for the instability of short range trends as demonstrated by various historical abrupt changes. Using 1966-1972 data, the Commission made a "high" estimate of 485 Mcf per foot, and using the 1963-1972 data, the Commission made a "low" estimate of 559 Mcf per foot. Productivity for 1972 had been 286 Mcf per foot. The Commission apparently gave consideration to all factors involved in the productivity determination and arrived at an accommodation of the competing theories. That accommodation, although not the

only one which could be made, is sufficiently supported by the record to withstand judicial review.

D. *Move to Discounted Cash Flow Model in 699-H*

[10] The FPC's choice of the Discounted Cash Flow (DCF) methodology in Opinion 699-H is the subject of attack from all quarters. This accounting process focuses on cash flow over a set period of time rather than on net income in any one year. The underlying principle is that money has a time value. An amount received a year from now, for example, is worth less than an equal amount currently in hand. This is the principle upon which bonds bearing below-market rates of interest are discounted. Similarly, an expenditure made in year 1 is more costly than an equal expenditure made in year 2.

Discounted Cash Flow accounting focuses on two factors: net cash outflow and net cash inflow. In the FPC model all calculations are made by reference to the first year of production. Net investments (cash outflow) made during the four years prior to production of natural [1080] gas are increased at a 15 percent compounded annual rate to give a value as of the first year of production. This 15 percent annual rate reflects the permissible rate of return allowed by the FPC.

In the second stage of the model, the FPC projects future net cash inflows (future gross revenues less annual expenses) for each year of gas production. The model apparently assumes that operations will terminate after 17 years of gas production. These yearly amounts are discounted by a 15 percent annual rate, again a reflection of allowable return on investment. (Future net cash inflows are the equivalent of installment payments on indebtedness. If such payments are discounted by a specific percentage,

that discount represents the interest which the lender receives as a return on his investment).

The final calculation of the FPC model is to simply say that future cash inflows, discounted at a 15 percent rate to allow a 15 percent return, must equal previous cash outflow in the form of start-up costs.

The producers attack the injustice of this model in the context of its inclusion of federal income tax credits and exclusion of tax liabilities in excess of those credits. In addition these petitioners variously challenge the time lag and future cash flow assumptions and the failure to provide for cost increases. One consumer group, the American Public Gas Association, questions assumptions about the rate of production and depletion, and use of trended drilling costs. The most serious challenge which the consumer groups bring is their assertion that this new methodology was adopted in midstream, without a sufficient evidentiary foundation, and that the adoption of DCF resulted in an unreasonable increase in the rate for natural gas from 42¢ per Mcf to 50¢. Without delving into the complexities of an esoteric costing methodology which counsel could scarcely describe in their briefs or at oral argument, we need only note that a reviewing court would go far afield in striking down an analytical model adopted by the Commission. As the Supreme Court long ago observed,

> Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling [citations omitted]. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.

FPC v. Hope Natural Gas Co., 320 U.S. 591, 602, 64 S.Ct. 281, 287, 88 L.Ed. 333 (1944). To attack the Discounted Cash Flow methodology, petitioners must therefore demonstrate that it results in an unjust and unreasonable end result. Petitioners failed to sustain this weighty burden of proof, either specifically with respect to the DCF methodology, or with respect to the FPC's rate structure in general.

E. *Federal Income Tax Issue*

[11] The producers strongly urge that the Commission committed reversible error when it excluded a federal income tax component from the national rate for natural gas. Rather than calculate an average rate of tax which would be uniformly factored into the cost for natural gas, the FPC instead set a rate exclusive of federal income tax and announced that when producers can demonstrate during an extraordinary relief proceeding that their natural gas operations resulted in actual income tax liability, higher rates will be permitted to reflect that tax.

One argument made against the Commission's refusal to augment the national rate by an average tax figure is that the Commission thereby acted inconsistently because it paradoxically reduced the rate by an average tax credit figure. There is no support in the statute or in precedent for the assertion that the Commission's treatment of federal taxes as a whole renders the area ratemaking concept deficient, illogical, or unfair.

[1081]

A second argument is made against the Discounted Cash Flow model's treatment of income tax. The model reduces recoverable start-up costs by the amount of tax credits generated by such costs and factors in automatic recovery of income taxes during the period of production only to

the extent that tax liability offsets previous tax credits. Thus the model assumes that income tax liability will not exceed income tax credits. It does not allow a return on initial investment which is sheltered by tax credits. Where tax liability exceeds credits, producers must petition for special relief. The producers' assertion that the FPC is taking a "double dip" against producer costs is not well taken. While average federal tax deductions are included to reduce start-up costs, an equal amount of tax liability is added to increase the cash flow which is later generated by gas rates during production, and individual tax liability in excess of this amount is recoverable at the time when such liability accrues through the special relief process. There is nothing so unjust or unreasonable about this treatment of tax costs as to require judicial intervention.

The Commission's policy choice of excluding an average tax liability figure in excess of tax credits was based on findings of fact, lending weight to our conclusion that the net effect of the DCF treatment of federal income tax is not unjust or unfair. Evidence demonstrated that the tax liability of producers varied widely, thus making an average extremely imprecise. The Commission also took note of the complexity of federal income tax provisions for gas producers, the ability of producers in some circumstances to indefinitely postpone tax liability, and the impending reduction of depletion allowances, all good reasons for eschewing a simple tax component which would be cemented into ratemaking for a long time to come. There appears to be no danger that a producer who actually pays taxes will not be able to recover that cost.

Producers also contend that the treatment of tax credits in the DCF model cheats them of a return on investment which is offset by tax deductions. By this argument producers ask us to substitute an alternative investment base for the one which the Commission selected. That would amount to the imposition of our discretionary choice upon an expert agency, which is not permitted.

F. *Rate of Return*

[12] The selection of a rate of return is overtly a factual determination and has been treated as such during the course of this litigation, but the Commission made an implicit policy choice which controls the nature of the relevant factual issues at hand. The Commission could probably have sought a rate of return which merely avoided charges of confiscation. But the FPC did more, seeking as it did a rate of return which at a minimum is competitive with other industries, and moreover encourages exploration. One petitioner, United Distribution Companies, challenged the 15 percent rate of return as being inadequate for these purposes, and asserts that the factual data supporting the decision to fix a 15 percent rate of return was not considered during the agency proceeding.

The Commission is to be upheld regardless of whether one views the rate of return as a factual determination which is subject to the substantial evidence standard of review, or as a parameter of the DCF model which is entitled to the less severe standard for reviewing a discretionary selection of policy and methodology. The record reveals that the Commission carefully evaluated average rates of return on capital invested in other industries and concluded that a zone of reasonableness spanned from 12 percent to 15 percent. The selection of the highest rate of return within the zone was based on the desire to provide the extra incentive which the Commission felt is needed to encourage increased exploration and development. We

find no ground for either reversing the policy of setting a rate which attracts capital into natural gas production, or setting aside the factual base that supports the choice of a 15 percent rate of return.

G. *Lease Acquisition Costs*

[13] Shell Oil and allied producers allege that the new national rate for natural gas understates Lease Acquisition Costs by approximately 25¢ per Mcf. They recite factual data which indicates a dramatic increase in bonuses paid by producers to the federal government in recent years for Outer Continental Shelf gas leases. Their evidence includes scattered federal lease information pertaining to acquisition costs from 1972 through 1974, and actual successful well cost data for 1973. The 1973 total, $2 billion dollars, was not available until February of 1975, three months after the issuance of Opinion 699-H. By contrast, the Commission based its lease acquisition cost estimates on six-year (1967-1972) cost averages and five-year (1968-1972) "Trended Data."

The Commission's projections are based on substantial evidence and cannot be reversed at this stage. Their evaluation is necessarily constrained by the time lag in compiling data of this kind. The recent developments to which Shell and others point is not so compelling as to require that 18 year projections be based on extraordinary recent developments. While the Commission is surely obligated to monitor these developments so that future adjustments provide for just and reasonable recoupment of lease acquisition costs, the Commission exercised proper discretion in basing its determination on long range rather than extraordinary and incomplete recent data.

H. *Net Liquid Credit*

[14] Net Liquid Credit is a cost equation component of relatively little import. Gas producers are able to capture a small amount of liquefiable petrocarbons as by-products of natural gas production. These petrocarbons are sold at a profit and are factored in as a credit which helps offset costs that are allocated through the rate charged to consumers of natural gas (the present credit amounts to 3.89¢ per Mcf). In setting the amount of the credit the Commission took notice of the fact that prices paid for this petroleum condensate are increasing, causing the credit to be understated. There is also evidence, however, that the amount of condensate produced is declining. The Commission in its opinion indicates that it is continuing the evaluation of these trends. While there is some merit in the charge that the evidence supporting the level set by the Commission is thin, it is not so insubstantial to warrant reversal of the Commission's evaluation of and response to these trends, especially in light of the implied promise to adjust the credit as further facts unfold. Certainly the magnitude of the issue is not sufficient to render the FPC order unjust and unreasonable.

I. *Refund, Work-off and Contingent Escalation Provisions*

[15] Under previous area rate agreements the FPC determined that certain producers were obligated to refund overcharges to pipelines. The producers were allowed, however, to "work-off" the obligation by receiving a 1¢ credit for each Mcf of new gas dedicated to interstate commerce in the affected area, as long as half of such gas is sold to the pipeline which was previously overcharged. *See, e. g., Permian Basin Area Rate Proceedings*, 50 F.P.C. 390

(1973); *Texas Gulf Coast Area Rate Proceeding*, 45 F.P.C. 674 (1971). In addition, the Commission provided for rate escalations contingent on the dedication of additional flowing gas to the interstate market by a given date. In Opinion Nos. 699 and 699-H the FPC provided that natural gas sold at the new national rate could not be used to discharge refund obligations or to trigger contingent escalations. Producers argue before this Court that this constitutes an improper retroactive modification of prior rate opinions. We disagree. By its orders which are here at issue, the FPC has established a new rate system for gas dedicated to interstate commerce after January 1, 1973, in addition to gas from certain other sources. The new national rate is the product of an independent determination of incentives, and, as it is in so many other regards, the new rate structure is not tied to previous determinations. Replacing one incentive structure with another or, viewed in another light, providing a new alternative rate system, is an exercise of Commission discretion which does not amount to retroactive rate regulation. *See Moss v. FPC*, 164 U.S.App. D.C. 1, 502 F.2d 461 (1974).

J. *Limited Term and Emergency Sales Procedures*

[16] In Opinion No. 699 the Commission modified its previous limited term and emergency sales procedures. *Cf.* 18 C.F.R. §§ 2.70, 157.29 (1974). The Commission provided that sales from the offshore federal domain made under both the limited term and the emergency sales procedures should not exceed the new national rate, and it limited the term of such sales to a single 60-day sale from a particular well or group of wells. The FPC reasoned that "the present gas shortage requires long-term solutions, not stop gap measures." It based its decision to limit these short-term procedures on substantial evidence showing that an inordinate amount of new deliveries to the interstate market for 1971 to 1973 are traceable to emergency and limited-term sales.

The FPC action is attacked on a number of fronts. The producers group contends that limited term and emergency sales should be allowed to exceed the national rate. A number of pipeline companies argued that the Commission erred in restricting sales from a well or a group of wells to a single 60-day period, and they assert that the Commission failed to establish sufficiently clear guidelines for the pipelines' recovery of their costs for emergency purchases.

As to the latter issue, the Commission has in fact stated the standard for acceptable cost recovery:

> If a pipeline seeks to purchase gas in interstate commerce for only a short period of time at a price in excess of the national rate, there must be credible evidence demonstrating that the gas is to be purchased at the lowest price for which the pipeline could have obtained the gas, and that such gas supply is not available for a long-term dedication at the present national rate.

Opinion No. 699-F. This standard is expanded by the statement in Opinion No. 699-B that pipelines should "be entitled to pay a rate for emergency purchases which a reasonably prudent pipeline purchaser would pay for gas under the same or similar circumstances."

We have approved the Commission's objective of achieving a monolithic national rate for natural gas. Its limitation of short-term emergency sales to 60 days, and its restriction of the price at which jurisdictional sales may be transacted are acceptable means to that end. By its action the FPC has protected the integrity of the new national rate and has

promoted long-term relationships between producers and pipelines. Its decision to restrain allowable short-term transactions was based on substantial evidence that an abundance of these transactions adversely affects long-term national ratemaking, and is therefore not reversible.

K. *Other Noncost Considerations*

[17, 18] Various petitioners argue that the Commission erred in failing to consider noncost factors which are created by market forces. Specifically, the producers base their argument for higher rates on a comparison between the FPC's new rate for natural gas and higher price of both oil and natural gas in the unregulated intrastate market. They argue that the national rate for regulated gas should equal the "commodity value" of gas determined by comparison with substitutable fuels such as oil. In essence, these petitioners would have us set the price of natural gas at the rate that the market would bear. The commodity price of gas would most likely be set by the prevailing price of oil and the cross-elasticity of demand between gas and oil. To accept this free market "commodity value" would be to eschew the congressionally mandated responsibility of rate regulation which is devised to reach a "just and reasonable" rate. Fixing a "just and reasonable" rate for a product sold in an inherently uncompetitive market requires more than mere subservience to national and international market forces. Just as the Natural Gas Act does not limit the Commission's determination to cost-related ratemaking, neither is the Commission obliged to incorporate specific noncost factors into its calculus.

As another way of phrasing their argument that the "commodity value" of natural gas should determine the national rate, a number of producers argue that the FPC

was erroneous in its use of cost-based ratemaking. But the Supreme Court has recently concluded upon a search for congressional intent that "the Commission lacks the authority to place exclusive reliance on market prices," *FPC v. Texaco, Inc.*, 417 U.S. 380, 400, 94 S.Ct. 2315, 2327, 41 L.Ed. 2d 141 (1973). The Commission's long and often judicially approved practice of basing rates on cost carries a substantial presumption of validity which places a heavy burden on those who would refute it. As noted above, the overall rate structure must be challenged on the basis of improper net effect. *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602, 64 S.Ct. 281, 88 L.Ed. 333 (1944). The cost-based national rate on review before us is experimental. It represents a dramatic increase in the allowable price for interstate gas. It is premature to decide, as the producers would have us decide, that this experimental price increase — the effect of which cannot yet be measured — is not enough.

The statutory standard for review of FPC policy requires an examination of the end result of a rate structure. Petitioners have not met their burden of demonstrating that the natural gas rate must reflect noncost, market conditions in order to be just and reasonable, *i. e.*, they have not shown that the FPC policy of basing the natural gas rate on cost rather than on market forces produces an end result which is harmful to the public interest.

CONCLUSION

Having carefully reviewed all of the various arguments against the validity of the Commission orders under review, we are constrained to uphold the Commission's action.

APPENDIX B

OPINION AND ORDER OF THE UNITED STATES COURT OF APPEALS FOR THE FIFTH CIRCUIT DENYING CERTAIN PETITIONS FOR REHEARING IN SHELL OIL COMPANY v. FEDERAL POWER COMMISSION (NATIONAL RATE CASES FOR NEW GAS) 525 F.2d 1063, DECIDED JANUARY 14, 1976.

SHELL OIL COMPANY et al., Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent.

No. 74-3330.

United States Court of Appeals,
Fifth Circuit.

Jan. 14, 1976.

Petitions for Review of Orders of the Federal Power Commission.

ON PETITIONS FOR REHEARING
(Opinion Oct. 14, 1975, 5 Cir., 520 F.2d 1061)

Before BELL, CLARK and RONEY, Circuit Judges.

PER CURIAM:

In its petition for rehearing, Rodman Corporation and others request us to reconsider our decision "to provide that the FPC (i) include a component for federal incomes taxes liability in the nationwide rate, (ii) eliminate the deduction of federal income tax credits from the nationwide average rate, or (iii) make 'crystal clear' that a *de novo* review of federal income tax in the current biennial review proceeding in FPC Docket No. RM 75—14 is permissible."

We agree that our decision should in no way be construed to foreclose a *de novo* review of federal income tax in the current biennial review proceeding in FPC Docket No. RM 75—14.

It is ordered that the petitions for rehearing filed in the above entitled and numbered cause be and the same are hereby denied.

APPENDIX C

OPINION NO. 699 OF THE FEDERAL POWER COMMISSION, OPINION AND ORDER PRESCRIBING UNIFORM NATIONAL RATE FOR SALES OF NATURAL GAS PRODUCED FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973 (ISSUED JUNE 21, 1974).

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UNITED STATES OF AMERICA

FEDERAL POWER COMMISSION

OPINION NO. 699

Just And Reasonable National Rates For) Docket No.
Sales Of Natural Gas From Wells Com-) R-389-B
menced On Or After January 1, 1973)

OPINION AND ORDER PRESCRIBING UNIFORM NATIONAL RATE FOR SALES OF NATURAL GAS PRODUCED FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973

Issued: June 21, 1974

*Transcript Page Number

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UNITED STATES OF AMERICA

FEDERAL POWER COMMISSION

[18 C.F.R. Parts 2 (§§2.56, 2.70), 154, 157 (§157.29)]
Before Commissioners: John N. Nassikas, Chairman; Albert B. Brooke, Jr., Rush Moody, Jr., William L. Springer, and Don S. Smith.

Just And Reasonable National Rate For Sales Of Natural Gas From Wells Commenced On Or After January 1, 1973 And New Dedication of Natural Gas To Interstate Commerce On Or After January 1, 1973	Docket No. R-389-B

OPINION NO. 699

OPINION AND ORDER PRESCRIBING UNIFORM NATIONAL RATE FOR SALES OF NATURAL GAS PRODUCED FROM WELLS COMMENCED ON OR AFTER JANUARY 1, 1973, AND NEW DEDICATIONS OF NATURAL GAS TO INTERSTATE COMMERCE ON OR AFTER JANUARY 1, 1973

(Issued June 21, 1974)

NASSIKAS, Chairman:

In this proceeding, we establish a single uniform national base rate of 42.0 cents per Mcf for following classes of jurisdictional sales of natural gas: (1) sales

made from wells commenced on or after January 1, 1973, (2) sales made pursuant to contracts executed on or after January 1, 1973, for the sale of natural gas in interstate commerce where such gas has not previously been sold in interstate commerce except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22 or 157.29, or (3) sales made pursuant to contracts executed on or after January 1, 1973, where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after January 1, 1973. This rate is found to be just and reasonable rate and is

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subject to adjustment for Btu content, State or Federal production, severance, or similar taxes, annual escalations of 1.0 cent per Mcf, and gathering allowances, which are also found to be just and reasonable. The rate is applicable to oil-well (casinghead) gas as well as gas-well gas, and shall remain in effect until modified by the Commission.

On April 11, 1973, the Commission issued a notice of proposed rulemaking in Docket No. R-389-B,[1] pursuant to the Administrative Procedure Act, 5 U.S.C. §551, *et seq.* (1970) (APA),[2] and Sections 4, 5, 7, 8, 14, 15, and 16 of the Natural Gas Act, 15 U.S.C. §717, *et seq.* (1970),[3] and proposed to issue rules establishing the just

1. 38 Fed. Reg. 10014 (1973).

2. 60 Stat. 237, 918, 993 (1946); 61 Stat. 37, 201 (1947); 62 Stat. 99 (1948); 80 Stat. 250 (1966).

3. 52 Stat. 822, 823, 824, 825, 829, 830 (1938); 56 Stat. 83, 84 (1984); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. §§717c, 717d, 717f, 717g, 717m, 717n, 717o (1970).

and reasonable rates for, and otherwise regulating, jurisdictional sales of natural gas on a nationwide basis. The single uniform just and reasonable rate to be determined by a final order in Docket No. R-389-B would apply to all jurisdictional sales of natural gas which is produced from wells commenced on or after January 1, 1973, except for those sales certificated under Order No. 431 or Order No. 491,[4] those sales certificated under Order

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No. 455,[5] or sales made by small producers under the terms of Order No. 428.[6] Such notice made all large producers respondents to the rulemaking proceeding, provided for the submission of written comments (submitted

4. 18 C.F.R. §2.70; *Policy With Respect To Establishment Of Measures To Be Taken For The Protection Of As Reliable And Adequate Service As Present Natural Gas Supplies And Capacities Will Permit,* Docket No. R-418, Order No. 431, 45 F.P.C. 570 (1971), as amended by Order No. 431-A, 48 F.P.C. 197 (1972).

See also, Policy With Respect To Establishment Of Measures To Be Taken For The Protection Of Reliable And Adequate Service For The 1973-1974 Winter Heating Season, Docket No. RM74-3, Order No. 491, 50 F.P.C._____ (September 4, 1973), as amended by Order No. 491-A, 50 F.P.C._____ (September 25, 1973), Order No. 491-B, 50 F.P.C._____ (November 2, 1973), Order No. 491-C, 50 F.P.C.____ (November 21, 1973). Stay of Order Nos. 491 and 491-B entered by the U. S. Court of Appeals (D.C. Cir.) was vacated in *FPC v. Consumer Federation of America, American Public Gas Association, American Public Power Association, National League of Cities—U. S. Conference of Mayors,* 414 U.S. 1117 (1973).

5. 18 C.F.R. §2.75; *Optional Procedure For Certificating New Producer Sales Of Natural Gas,* Docket No. 441, Order No. 455, 48 F.P.C. 218 (1972), as amended by Order No. 455-A, 48 F.P.C. 477 (1972), *appeal pending sub nom. John E. Moss, et al. v. F.P.C.,* Nos. 72-1837, *et al.* (D.C. Cir. September 11, 1972.)

6. *Exemption Of Small Producers From Regulation,* 45 F.P.C. 454 (1971), *as amended* 45 F.P.C. 548 (1971), *reh. denied,* 46 F.P.C. 47 (1971), *reversed, Texaco Inc., et al. v. F.P.C.,* 153 U.S. App. D.C. 195, 474 F.2d 416 (1972), *vacated* and *remanded,* 42 U.S.L.W. 4867 (U.S. June 10, 1974).

under oath) from all interested parties and the named respondents, and was accompanied by a Staff study on the estimated nationwide cost of finding and producing new nonassociated natural gas supplies.

The Commission in that notice did not propose any specific rates, terms, or condition in the notice, but stated that it would amend Section 2.56 of the Rules of Practice and Procedure, General Policy Statements and Interpretations (18 C.F.R. § 2.56) in accordance with its determinations based upon information contained in the responses submitted by the various parties and the Staff study accompanying the notice of proposed rulemaking.

The original notice of rulemaking was supplemented on March 21, 1974, when a "Notice Of Issuance Of Revised Staff Nationwide Cost Study And Staff Study Of American Gas Association Reserve Additions" was issued.[7] In the March 21, 1974, notice, the Staff cost estimates which accompanied the original notice of rulemaking in this proceeding were updated to reflect 1972 drilling cost

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data reported by the Joint Association Survey (1972 JAS) and nonassociated natural gas reserve additions for 1972 as reported by the American Gas Association (AGA). The Staff cost studies accompanying the April 11, 1973, notice were revised in the March 21, 1974, notice to reflect a 10.5 year investment life for updated test periods of seven years (1966-1972) and the average of the 11, 16, and 26 year average productivities (1966-1972; 1957-1972; 1947-1972). Additional cost studies

7. 39 *Fed. Reg.* 11310 (1974).

for a ten-year test period (1963-1972) and a four-year test period (1969-1972) were also presented in Revised Appendix B. Appendix B-1 to the associated natural gas reserve additions for selected leases in the Southern Louisiana Offshore Federal Domain. The results of this study indicated that AGA reserve additions for 1971 and 1972 might be understated by approximately 1.7 trillion cubic feet (Tcf). In addition to comments directed to the two Staff cost studies, the Commission also requested comments upon a number of issues, *viz.*, the appropriate method for determining the rate of return, the utilization of full cost accounting, the utilization and reliability of the more recent cost data, the utilization of trending to determine new gas costs and the time series which would form the basis for the statistical trending, whether an additional allowance should be provided for deeper drilling and water depths, and what non-cost factors are appropriate for consideration in the costing of new gas supplies and how such factors can be quantified.

Further, by order of April 12, 1974,[8] the Commission extended the time for the filing of comments in response to the March 21, 1974, notice and required that certain issues presented by the United Distribution Companies and their consultant, Mr. William J. Ogden, be presented at a conference to be held in this proceeding on April 16, 1974. This conference had been requested by the American Gas Association in an effort to resolve the disparity between nonassociated natural gas reserve additions for 1971 and 1972 as reported by

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the American Gas Association and the reserve additions

8. 39 *Fed. Reg.* 13976 (1974).

found by our Staff to be related to some 31 leases in the offshore Southern Louisiana area.[9]

In summary, the continuing and deepening natural gas shortage[10] and critical shortages of other energy sources which have resulted in a national energy emergency requires that this Commission take all prudent steps to insure that the rates allowed for natural gas sold in interstate commerce are adequate to bring forth the requisite supplies to fulfill reasonable demand while protecting the "consumers against exploitation at the hands of natural-gas companies."[11] Thus, the Commission faces a formidable task: establishing rates high enough to provide the economic incentive for the unprecedented task of finding enormous volumes of new gas supplies but not so high that the natural gas consumer is exploited during a time of shortage.

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To that end, we have determined that a single uniform national rate promulgated in this rulemaking proceeding will enable us to establish just and reasonable rates for

9. Notice of this conference was published in the *Federal Register* on April 9, 1974, 39 *Fed. Reg.* 13199 and a revised notice indicating that the meeting would be of record was published in the *Federal Register* on April 9, 1974. 39 *Fed. Reg.* 13199.

The letter from the American Gas Association requesting the meeting was made a part of the public record and the transcript of the meeting (1 Tr. 5).

10. The natural gas shortage has been judicially recognized. *E.g., F.P.C. v. Louisiana Power & Light Co.*, 406 U.S. 621 (1972); *Placid Oil Company, et al. v. F.P.C.*, 483 F.2d 880 (5th Cir. 1973), *affirmed sub nom. Mobil Oil Corporation, et al. v. F.P.C.*, 42 U.S.L.W. 4842 (U.S. June 10, 1974). *Shell Oil Company, et al. v. F.P.C.*, 484 F.2d 469 (5th Cir. 1973), *cert. denied sub nom. Mobil Oil Corp. v. F.P.C.*, Nos. 73-438, *et al.* (June 17, 1974).

11. *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672, 685 (1954).

natural gas sold in interstate commerce without the inherent delays and stale records which have accompanied the traditional adjudicatory method of regulating producer rates.[12] The prescription of a uniform national rate for all areas will avoid essentially duplicative procedures and evidence to prescribe just and reasonable rates for the various natural gas producing areas of the Nation, and will enable the Commission to utilize its manpower and resources for more effective administration of the Natural Gas Act. By the use of the Commission's rulemaking powers in this and future proceedings, we and future Commissions will be able to prescribe just and reasonable rates on a biennial basis using the most recent evidence and bringing expertise gained in related proceedings to bear upon this problem of assuring an adequate supply of natural gas for the Nation.[13]

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I.

PROCEDURAL ISSUES

Most of the parties responding to the notice of the proposed rulemaking commented favorably upon the Commission's attempt to arrive at an expeditious determination of a single uniform national rate for all jurisdictional sales made from wells commenced on or after January 1,

12. The first area rate proceeding, *Permian Basin Area Rate Proceeding, et al.*, 34 F.P.C. 159 (1965), consumed five years before the Commission, and it was an additional three years before the Commission's decision was affirmed by the Supreme Court in the *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

13. *Cf. City of Chicago v.* FPC, 147 U.S. App. D.C. 312, 458 F. 2d 731 (D.C. Cir. 1971), cert. denied, 405 U.S. 1074 (1972); *Sun Oil Co. v. FPC*, 256 F.2d 233, 240-241 (5th Cir.), *cert. denied*, 358 U.S. 872 (1958).

1973. However, a number of parties expressed reservations concerning the Commission's decision to establish a uniform rate for all producing areas in view of the differing conditions of the Rocky Mountain Area, the Appalachian-Illinois Basin Area, and the Deep Anadarko Basin.[14]

The Commission has determined that the single uniform national rate established herein should be applicable to the lower 48 states (onshore and offshore). The current natural gas shortage requires that the Commission act expeditiously to establish a generally applicable rate for all producing areas before areas that may present special cost circumstances are accorded additional consideration to determine if different rates should be established in those areas to compensate for local peculiarities. The fact that the rate determined herein may not be as advantageous to some producers as others is not controlling. The Supreme Court held in the *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968), that the use of average nationwide costs to establish an area rate was a permissible means of rate regulation under the Constitution, 390 U.S. 747 at 768-770, and the Natural Gas Act, 390 U.S. 747 at 774-777. The cost of "new gas" in each of the area rate cases (with the single exception of the Appalachian-Illinois Basin Proceeding) was determined from nationwide data and then adjusted for local production taxes and gathering practices. The end result of the area rate experiment was in effect a uniform national rate for new gas by areas based upon the evidentiary record in

14. *See* for example the comments of Cabot Corporation, The Public Utilities Commission of the State of Colorado, Colorado Interstate Gas Company, Columbia Gas System Service Corporation, Equitable Gas Company, The GHK Company, Public Service Commission for the State of New York, and Public Service Company of Colorado.

those individual area rate proceedings. During the course of the various area rate cases,

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the data base upon which the Commission relied for its determination of rates was updated to reflect the recent data which was considered to be more representative of current cost trends than the older data relied upon in the first Permian Proceeding. Thus, the various rates are not absolutely identical. In this proceeding the average nation-wide cost of "new gas" will be applied to all areas (on-shore and offshore) subject to annual escalations and adjustments for production taxes, Btu content, and gathering allowances which are set forth in the rate structure. Furthermore, producers may petition the Commission for special relief from the national rate under the circumstances and limitations hereinafter set forth. The Commission has concluded that the question of whether special area rates should be established for the Appalachian-Illinois Basin Area, the Rocky Mountain Area, and the Deep Anadarko Basin will be deferred pending further consideration of that matter.

Two parties responding to the notice of proposed rulemaking (Public Service Commission for the State of New York and Dr. Keith Brown) raised the issue of whether certain gas producing areas have a "locational value" due to their proximity to major natural gas consuming areas. This question is pertinent to the prices established for the areas outside of the major producing areas of the Southern and Southwestern states, *i.e.*, the Appalachian-Illinois Basin Area and the Rocky Mountain Area. As for the major producing areas of the Southern and Southwestern states, it should be noted that the natural gas flowing into

the interstate markets from those states flows to gas consuming markets throughout the United States, and it is not possible to determine a single "locational value" for these areas which are connected to pipelines serving markets dispersed throughout the United States. Moreover, any attempt to assign a number of "locational values" to any given area would hopelessly and needlessly complicate the rate structure established herein.

Furthermore, the Commission is aware of the fact that considerable inequity and economic dislocation could result from a fundamental restructuring of the

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basic area rate concept which is, in essence, a national rate concept with respect to "new gas" supplies. A further consideration which supports our conclusion that a "locational value" concept should be rejected in this proceeding is the fact that it would be counter-productive during an acute gas shortage to impose an economic penalty on natural gas supplies to be discovered in the more prolific areas which are located at great distances from the major centers of consumption.

Several parties herein have challenged our use of rulemaking procedures in this proceeding.[15] The thrust of their contentions is that the Fifth Amendment of the United States Constitution, the Natural Gas Act, 15

15. Amerada Hess Corporation, American Public Gas Association (APGA), Chevron Oil Company, Western Division, Exxon Corporation, Marathon Oil Company, Mobil Oil Corporation, Phillips Petroleum Company, Public Utilities Commission of the State of Colorado, Superior Oil Corporation, Texaco Inc., The California Company, a division of Chevron Oil Co., and Senator James G. Abourezk.

Associated Gas Distributors (AGD) urged the Commission to allow oral argument, but did not oppose the use of rulemaking procedures to establish rates.

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U.S.C. §717, *et seq.*, and the Administrative Procedure Act, 5 U.S.C. §551, *et seq.*, require the Commission to utilize formal adjudicatory procedures in ratemaking proceedings. This particular issue has been before the Courts in several recent cases, and in each instance the Commission's authority to establish rates via rulemaking was upheld. *American Public Gas Association, et al. v. F.P.C.*, Nos. 71-1812 and 71-1873 (D.C. Cir., May 23, 1974); *Mobil Oil Corporation v. F.P.C.*, ___U.S. App. D.C. ___, 483 F.2d 1238 (D.C. Cir. 1973); *Phillips Petroleum Co. v. F.P.C.*, 475 F.2d 842 (10th Cir. 1973), *cert. denied sub nom. Chevron Oil Co., et al. v. F.P.C.* No. 73-91, 42 U.S.L.W. 3401 (U.S., January 14, 1974).

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This is not the first time that this Commission has utilized its rulemaking powers to establish rates. In addition to the proceedings reviewed by the Tenth Circuit in the *Phillips* case and the proceedings reviewed by the D.C. Circuit in the *APGA* case, the Commission utilized its rulemaking authority, after strict compliance with the Administrtive Procedure Act (5 U.S.C. §551, *et seq.*), to establish just and reasonable rates for "old" and "new" gas and to impose an indefinite moratorium on rate increase filings with respect to natural gas produced in the Appalachian and Illinois Basin Areas.[16] The Commission's decision in that proceeding was not appealed.

Furthermore, the petitions to review Opinion No. 658,[17]

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16. *Area Rates For The Appalachian And Illinois Basin Areas, et al.*, Docket No. R-371, *et al.*, Order No. 411, 44 F.P.C. 1112 (1970), *as amended*, Order No. 411-A, 44 F.P.C. 1334 (1970), *reh. denied*, Order No. 411-B, 44 F.P.C. 1487 (1970).

17. *Area Rates For The Rocky Mountain Area*, Docket No. R-425, Opinion No. 658, 49 F.P.C. 924 (issued April 11, 1973), *appeal*

which established just and reasonable rates for natural gas sold under contracts dated prior to October 1, 1968, and produced from wells drilled (commenced) prior to January 1, 1973, and made the initial rates established in Order No. 435[18] applicable to natural gas sold under contracts dated between October 1, 1968, and June 17, 1970, until such time as a final order is issued in this proceeding, were dismissed pursuant to a motion filed by the petitioners (Exxon Corporation, *et al.*) on February 22, 1974.

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It is settled that the United States Constitution does not require the use of formal adjudicatory procedures in ratemaking proceedings by this Commission where, as here, the rates established will apply to groups generally and no effort is made to single out any individual or company "for special consideration based on its own peculiar circumstances." *United States v. Florida East Coast Ry., et al.*, 410 U.S. 224, 246 (1973); *Mobil Oil Corp. v. FPC*, 483 F.2d 1238, 1250; *APGA, et al. v. FPC*, slip opinion at p. 10. Therefore, any question as to the adequacy of the procedures followed in this case reduces to whether or not the procedures satisfy the requirements of the Natural Gas Act and the Administrative Procedure Act.

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pending sub nom. Exxon Corporation, et al. v. FPC, No. 73-1854 (D.C. Cir. filed August 6, 1973), *motion to dismiss appeal granted* February 22, 1974.

18. *Initial Rates For Future Sales Of Natural Gas For All Areas*, Docket Nos. R-389 and R-389-A, Order No. 435, 46 F.P.C. 68 (1971), *affirmed sub nom. American Public Gas Association v. F.P.C.*, No. 71-1812 (D.C. Cir., decided May 23, 1974).

We believe that any question as to the adequacy of the procedures followed in this case that may have been raised by the *Mobil Oil* decision where laid to rest by the subsequent decision of the Supreme Court not to review the *Phillips* decision. Moreover, the Court of Appeals for the District of Columbia Circuit has distinguished its holding in the *Mobil Oil* case in its holding that the Commission has the authority to establish initial rates by the use of rulemaking procedures. *American Public Gas Association, et al. v. FPC,* Nos. 71-1812 and 71-1873 (D.C. Cir., decided May 23, 1974).

In the *Mobil Oil* case, the Commission's order was reversed on the basis of an inadequate record and lack of proper notice to the various parties. It was on this basis that the *Mobil* case was distinguished in *APGA, et al. v. FPC, supra,* slip opinion at p. 10:

> In the *Mobil Oil* case there was no adequate notice, and much of the data relied upon by the Commission was provided in an informal and to some extent *ex parte* conference, as distinguished from an adversary setting.

We have, in this proceeding, provided adequate notice to all interested persons with respect to the proposed goal of the Commission and the type of information and data upon which

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our decision would be based. Indeed, a second notice enumerating specific questions upon which the Commission desired additional comments was served upon all parties of record.

While the *APGA* case dealt with initial rates, we are of the opinion that the same rationale applies to the

establishment of just and reasonable rates. The Court there found that the Commission's procedures were consistent with the due process rights of the petitioners and stated (slip opinion, p. 10):

> The issues were clearly stated from the onset and the petitioners were given an adequate opportunity to participate in developing evidence bearing upon those issues. There is no reason to believe that the exchanges or dialogue between and among the parties were so inadequate as a mechanism for finding the facts that a trial-type proceeding was necessary.

Likewise, in this proceeding, every party has been given an opportunity to submit two sets of responses and replies to the responses of all other parties. Thus, no party can be heard to complain that he lacked an adequate opportunity to develop his case before the Commission.[19]

Since the Natural Gas Act does not require a "hearing on the record" in ratemaking proceedings,[20] the Commission is not required to hold an adjudicatory hearing under the

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formal procedures set forth in Sections 556 and 557 of the Administrative Procedure Act, 5 U.S.C. §§556 and 557, before establishing generally applicable producer rates. As the Court noted in *APGA, et al. v. FPC, supra,*

19. In the April 12, 1974, order in this proceeding, we emphasized the right of all parties to file "any comments which they desire to place before the Commission for consideration." (*Mimeo,* p. 3, footnote omitted.)

20. Section 4(e), 15 U.S.C. §717c(e), and Section 5(a), 15 U.S.C. §717d(a), require a "full hearing" and a "hearing", respectively, before the Commission exercises its authority to establish "just and reasonable" rates.

a trial is not a prerequisite to the establishment of rates (slip opinion, p. 7):

> The Commission is not forced to adopt the procedures of a trial, with formal hearings, oral testimony under oath, cross examination, and the like. Evidentiary submission in written form may be sufficient. *United States v. Florida East Coast Rwy Co.*, 410 U.S. 224 (1973); *FPC v. Texaco, Inc.*, 377 U.S. 33, *rehearing denied*, 377 U.S. 984 (1964); *Mobil Oil Corp. v. FPC*, ____ U.S. App. D.C. ____, 483 F.2d 1238 (1973).

Thus, we find that the procedures adopted in this proceeding which allowed the filing of two sets of initial and reply comments by all parties provide a sufficient basis for the acquisition of the information which we require in order to arrive at a final decision.

Furthermore, we find no basis or need for a formal hearing with oral cross examination in this proceeding. While the parties have not been given an opportunity to orally cross examine the statements of the other parties to this proceeding, they have been given an opportunity to file any and all comments they desire to file. Even the Administrative Procedure Act does not provide an untrammelled right to oral cross examination in formal proceedings. Section 556(d), 5 U.S.C. §556(d), provides in part:

> A party is entitled to present his case or defense by oral or documentary evidence, to submit rebuttal evidence, and to conduct such cross examination as may be required for a full and true disclosure of the facts. In rulemaking . . . an agency may, when a

> party will not be prejudiced thereby, adopt procedures for the submission of all or part of the evidence in written form.

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Those parties who have asserted a right to oral cross examination in this proceeding have failed to demonstrate that they will be prejudiced by the lack of such cross examination in this proceeding. No party has pointed out any specific questions or issues that it would raise upon oral cross examination or why it could not adequately "test, criticize, and illuminate the flaws in the evidentiary basis being advanced regarding a particular point" by other parties in its own written submissions. (See *Mobil Oil Corp. v. FPC*, 483 F.2d 1238, 1262-1263). In such circumstances, we are not required to speculate as to whether or not there are issues or questions which require oral cross examination. Our examination of the submittals of all parties to this proceeding discloses no issue which requires a formal adjudicatory hearing with oral cross examination.[21]

Because our decision must be based upon substantial evidence contained in the record of the proceeding as a whole, we are of the opinion that we should set forth those documents which constitute the evidentiary record of this proceeding so that all parties will be aware of all the evidence which was considered by the Commission

21. An on-the-record public conference was held in this proceeding on April 16, 1974, at the request of the American Gas Association (AGA) to discuss Appendix B-1 to the notice issued March 21, 1974, in this proceeding. Certain parties which have questioned our use of AGA reserve data did not participate in the conference, yet they continue to oppose the use of such data and demand a formal hearing on the issue.

in reaching its decision.[22] The evidentiary record of this proceeding will consist of (1) the notice of rulemaking and the Staff cost study appended thereto which were issued on

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April 11, 1973 (38 *Fed. Reg.* 10014 (1973)); (2) the notices filed by the various parties of the intention to respond to the notice of proposed rulemaking which were required to be filed on or before April 30, 1973; (3) the written comments of all parties, including the various cost studies and other evidentiary materials submitted therewith, filed on or before May 16, 1973, and on or before June 1, 1973; (4) the notice of March 21, 1974 (39 *Fed. Reg.* 11310 (1974)); (5) the notices of the public conference held in this proceeding on April 16, 1974 (39 *Fed. Reg.* 12929, 13199 (1974)); (6) the order of April 12, 1974 (39 *Fed. Reg.* 13976 (1974)); (7) the transcript of the April 16, 1974, conference in this proceeding;[23] (8) the comments filed by the parties to this proceeding on or before May 7, 1974, and on or before May 29, 1974; and (9) the materials incorporated by reference into the record of this proceeding as hereinafter set forth.[24]

22. *Mobil Oil Corp. v. FPC*, 483 F.2d 1238 at 1258-1260 (1973); *American Public Gas Association, et al. v. FPC, supra*, slip opinion at p. 8 *citing United States v. Florida East Coast Rwy. Co.*, 410 U.S. 224, 241 (1973).

23. The transcript consists of one volume containing 73 pages.

24. All late filings in this proceeding are deemed to have been timely filed and have been considered by the Commission.

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II

SUPPLY AND DEMAND

A. SUPPLY

1. THE NATURAL GAS SHORTAGE

The pervasive natural gas shortage, which this nation is currently experiencing and which is expected to continue beyond the 1980's, requires that this Commission promulgate producer pricing policies which will attract long-term dedications of new natural gas supplies to the interstate market.

As can be seen in Table 1, the natural gas reserves reported by jurisdictional pipelines have declined from 198.1 trillion cubic feet (Tcf) in 1967 to a low of 148.6 Tcf in 1972. This represents a decline of approximately 50 Tcf in a six year period, and the decline was also approximately 25 percent of the reserves existing in 1967.[25] During this same six-year period (1967 through 1972), the findings to production ratio (F/P) averaged around 0.5; this means that the consumption of natural gas was approximately twice the new supplies of natural gas discovered during the period. These trends must be reversed if we are to meet future demands for natural gas.

Our analysis of both oil and gas drilling activities since 1945 indicates that there has been a decline in exploratory and developmental drilling in recent years. We believe that this decline in drilling activity is, at

25. Preliminary data reported by pipelines on Form 15 for 1973 shows reported reserves are 134.4 Tcf or a decline of 63.7 Tcf since 1967.

least in part, responsible for the decline in new natural gas supplies discovered in recent years. This downward trend must be reversed if we expect to meet essential demands for natural gas from domestic sources and attain our objective of a national capacity for self-sufficiency in energy resources. Thus, one of the primary goals which we have in establishing a national rate is to set a rate sufficient to encourage the exploratory and developmental drilling which is required to discover and produce the natural gas supplies necessary to attain an objective of self-sufficiency in natural gas supplies available for delivery to the ultimate consumer.

TABLE I
Comparison of AGA and
Form 15 Data (Lower 48 States)
(Volumes in Trillions of Cubic Feet)

	End of Year Reserves		Net Production		Reserve to Production Ratio		Reserve Additions		Finding to Production Ratio	
	AGA	Form 15	AGA	Form 15	AGA	Form 15	AGA	Form 15	AGA	Form 15
1963	274.5	188.5	14.5	9.4	18.9	20.2	18.1	NA	1.2	NA
1964	279.4	189.2	15.3	10.0	18.3	18.9	20.1	10.7	1.3	1.1
1965	284.5	192.1	16.3	10.4	17.5	18.5	21.2	13.3	1.3	1.3
1966	286.4	195.1	17.5	11.1	16.4	17.5	19.2	14.1	1.1	1.3
1967	289.3	198.1	18.4	11.8	15.7	16.8	21.1	14.8	1.1	1.2
1968	282.1	195.0	19.3	12.6	14.6	15.5	12.0	9.5	0.6	0.8
1969	269.9	187.6	20.6	13.4	13.1	14.0	8.3	6.0	0.4	0.5
1970	259.6	173.6	21.8	14.1	11.9	12.3	11.1	0.1	0.5	0.0
1971	247.4	161.3	21.9	14.2	11.3	11.4	9.4	1.9	0.4	0.1
1972	234.6	148.6	22.4	14.2	10.4	10.5	9.4	1.5	0.4	0.1

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Table 2 shows that in 1956 some 30,528 domestic oil wells were drilled as compared to a total of only 11,306 oil wells drilled in 1972. Gas-well drilling has shown a similar decline from the peak of gas-well drilling activities in 1961 when some 5,459 successful gas wells were completed as compared to a total of only 3,830 gas wells completed in 1971. This downward trend in gas-well drilling was reversed in 1972 when 4,928 gas wells were completed, and it continued through 1973 when some 6,385 gas wells were drilled as compared to 4,928 gas wells drilled in 1972.[26]

As indicated by Table 3, the total number of exploratory wells drilled has declined sharply since 1964 and exploratory gas-well drilling for 1967 through 1972 was at lower levels than the preceding decade. Both the total number of wells drilled and the total number of exploratory wells drilled per year for the past five to six years are considerably fewer than the total number of wells drilled and the total number of exploratory wells drilled approximately 15 years ago while the demand for oil and gas has doubled in that 15 year period.

The reversal of drilling activity which occurred in 1972 did not carry through to 1973 with the exception of the number of gas wells completed which again increased over the number completed the previous year. Overall, 1973 showed a continued increase in gas drilling activity with both exploratory and developmental gas well footages at

26. FPC Office of Economics, *Gas Supply Indicators—Fourth Quarter 1973 and Annual Review,* April 1974, p. 21.

the highest levels ever reported.[27] The number of oil wells drilled in 1973 continued to decline over the number drilled in previous years. There were other encouraging signs in that number of rotary drilling rigs which were active during the year was the highest active number since 1966. Other indicators seemed to show a leveling off in the increased activity as bottlenecks and supply shortages began to appear in the fourth quarter of 1973.[28]

27. *Id.,* p. 12. The total footage for 1973 was 33.0 million feet compared with the previous high of 29.1 million feet in 1961.

28. *Id.,* p. 8.

TABLE 2

TOTAL WELLS DRILLED FOR HYDROCARBONS
(Footage Drilled in Thousands of Feet)

Year	Total* Wells	Footage	Average Depth	Oil Wells	Footage	Average Depth	Gas Wells	Footage	Average Depth	Dry Holes	Footage	Average Depth	Successful Wells (%)
1945	23,601	87,545	3,709	13,738	50,956	3,709	2,637	9,300	3,527	7,226	27,289	3,777	69.4
1946	27,975	97,393	3,481	15,962	56,632	3,548	3,510	11,801	3,362	8,503	28,960	3,406	69.6
1947	30,833	109,358	3,547	17,478	62,802	3,593	3,809	13,169	3,457	9,546	33,387	3,497	69.0
1948	36,659	131,187	3,579	21,760	77,307	3,553	3,387	12,312	3,635	11,512	41,567	3,611	68.6
1949	37,312	135,619	3,635	21,352	79,428	3,720	3,363	12,437	3,698	12,597	43,754	3,473	66.2
1950	42,050	157,358	3,742	23,812	92,695	3,893	3,439	13,685	3,979	14,799	50,978	3,445	64.8
1951	43,643	172,145	3,944	23,179	95,106	4,103	3,438	13,946	4,056	17,026	63,093	3,706	61.0
1952	44,563	184,134	4,132	23,290	98,147	4,214	3,514	15,257	4,342	17,759	70,730	3,983	60.1
1953	47,740	194,245	4,069	25,323	102,135	4,033	3,968	18,248	4,599	18,449	73,861	4,004	61.4
1954	51,109	208,009	4,070	28,141	113,362	4,028	4,038	18,857	4,670	18,930	75,790	4,004	63.0
1955	55,150	226,182	4,101	30,432	121,149	3,981	4,266	19,931	4,672	20,452	85,102	4,161	62.9
1956	57,170	233,280	4,080	30,528	120,351	3,942	4,531	22,738	5,018	22,111	90,191	4,079	61.3
1957	51,995	217,046	4,174	27,364	110,043	4,021	4,475	23,836	5,326	20,156	83,167	4,126	61.2
1958	46,941	193,304	4,118	23,774	93,105	3,916	5,005	25,556	5,106	18,162	74,643	4,110	61.3
1959	47,563	200,693	4,220	24,043	94,611	3,935	4,931	26,607	5,396	18,589	79,476	4,275	60.9
1960	45,547	192,078	4,217	22,233	86,538	3,892	5,129	28,199	5,498	18,185	77,341	4,253	60.1
1961	44,254	189,633	4,285	21,413	85,508	3,993	5,459	29,179	5,345	17,382	74,947	4,312	60.7
1962	44,158	194,634	4,408	21,727	88,432	4,070	5,353	28,950	5,408	17,078	77,253	4,524	61.3
1963	41,467	182,649	4,405	20,135	81,809	4,063	4,570	24,533	5,368	16,762	76,307	4,552	59.6
1964	42,293	187,420	4,431	19,905	80,463	4,042	4,694	25,597	5,453	17,694	81,359	4,598	58.2
1965	38,773	174,882	4,510	18,065	73,322	4,059	4,482	24,931	5,562	16,226	76,629	4,723	58.2
1966	35,730	165,420	4,630	16,216	67,430	4,158	4,321	25,636	5,933	15,193	72,353	4,762	57.5
1967	32,234	141,357	4,385	15,329	58,634	3,825	3,659	21,580	5,898	13,246	61,143	4,616	58.9
1968	30,599	144,970	4,738	14,331	59,517	4,153	3,456	20,716	5,994	12,812	64,737	5,053	58.1
1969	32,187	157,108	4,881	14,368	61,582	4,286	4,083	24,162	5,918	13,736	71,363	5,195	57.3
1970	28,120	139,266	4,953	13,020	57,092	4,385	3,840	22,889	5,961	11,260	59,285	5,265	60.0
1971	25,851	124,240	4,806	11,858	48,552	4,094	3,830	22,624	5,907	10,163	53,064	5,221	60.7
1972	27,291	134,602	4,932	11,306	48,534	4,293	4,928	26,766	5,431	11,057	59,303	5,363	59.5

Sources: 1945-1966; World Oil, 1967-1972; AAPG-API

* Includes Alaska. Excludes service wells.

TABLE 3

TOTAL EXPLORATORY WELLS DRILLED FOR HYDROCARBONS
(Footage Drilled in Thousands of Feet)

Year	Total* Wells	Footage	Average Depth	Oil Wells	Footage	Average Depth	Gas Wells	Footage	Average Depth	Dry Holes	Footage	Average Depth	Successful Wells (%)
1945	5,610	23,049	4,109	836	3,750	4,486	376	1,772	4,712	4,398	17,527	3,985	21.6
1946	5,759	22,338	3,879	762	3,455	4,534	375	1,832	4,885	4,622	17,052	3,689	19.7
1947	6,775	26,393	3,896	982	4,281	4,359	396	1,895	4,787	5,397	20,217	3,746	20.3
1948	8,013	32,751	4,087	1,098	4,883	4,447	365	2,306	6,319	6,550	25,562	3,903	18.3
1949	9,058	34,798	3,842	1,406	5,950	4,232	424	2,409	5,682	7,228	26,439	3,658	20.2
1950	10,306	40,175	3,898	1,583	6,862	4,335	431	2,356	5,466	8,292	30,957	3,733	19.5
1951	11,756	49,344	4,197	1,763	8,125	4,609	454	2,496	5,497	9,539	38,723	4,059	18.9
1952	12,425	55,615	4,476	1,776	8,491	4,781	559	3,394	6,071	10,090	43,731	4,334	18.8
1953	13,313	60,664	4,557	1,981	9,432	4,761	699	3,952	5,654	10,633	47,280	4,447	20.1
1954	13,100	59,601	4,550	1,985	9,409	4,740	726	4,399	6,059	10,389	45,792	4,408	20.7
1955	14,942	69,20[illegible]	4,632	2,236	10,774	4,819	874	5,212	5,964	11,832	53,220	4,498	20.8
1956	16,207	74,337	4,587	2,267	11,111	4,901	822	5,179	6,301	13,118	58,047	4,425	19.1
1957	14,714	69,181	4,702	1,945	9,794	5,036	865	5,967	6,898	11,904	53,420	4,488	19.1
1958	13,199	61,494	4,658	1,745	8,712	4,993	822	5,472	6,657	10,632	47,300	4,449	19.4
1959	13,191	63,253	4,795	1,702	8,545	5,021	912	6,031	6,613	10,577	48,676	4,602	19.8
1960	11,704	55,831	4,770	1,321	6,829	5,170	868	5,466	6,298	9,515	43,535	4,575	18.7
1961	10,992	54,442	4,953	1,157	5,900	5,099	813	5,249	6,457	9,022	43,293	4,799	17.9
1962	10,797	53,616	4,966	1,211	6,205	5,124	771	5,187	6,728	8,815	42,223	4,790	18.4
1963	10,664	53,485	5,015	1,314	6,409	4,877	664	4,230	6,370	8,686	42,847	4,933	18.5
1964	10,747	55,497	5,164	1,219	6,715	5,509	577	4,204	7,285	8,951	44,578	4,980	16.7
1965	9,466	49,204	5,198	946	5,366	5,672	515	3,757	7,295	8,005	40,081	5,007	15.4
1966	10,313	55,223	5,355	1,030	5,880	5,708	578	4,881	8,445	8,705	44,462	5,108	15.6
1967	9,059	49,124	5,423	1,039	5,990	5,765	556	4,231	7,609	7,464	38,903	5,212	17.6
1968	8,879	50,958	5,739	863	5,036	5,835	430	3,320	7,720	7,586	42,603	5,616	14.6
1969	9,701	57,466	5,924	1,084	6,563	6,054	616	4,985	8,092	8,001	45,918	5,739	17.5
1970	7,693	45,253	5,882	790	5,055	6,399	481	3,675	7,639	6,422	36,524	5,687	16.5
1971	6,922	40,388	5,835	651	3,712	5,701	437	3,328	7,616	5,834	33,347	5,716	15.7
1972	7,539	45,044	5,975	684	4,002	5,851	601	4,592	7,641	6,254	36,500	5,836	17.0

Source: AAPG - API
* Includes Alaska. Excludes stratigraphic and core tests.

[2653]

This continued upturn in gas well exploratory and developmental drilling is not adequate to discover and bring forth the supply of natural gas necessary to meet projected demands in view of the continued decline in annual additions to the nation's non-associated gas reserves.[29] Moreover, the continued decline in oil-well drilling activity means not only a short fall of domestic crude oil supplies but also a short fall of supplies of dissolved and associated gas that will be available for consumption. Unless we increase domestic exploratory and developmental drilling for both crude oil and natural gas, the Staff's forecast of annual natural gas supply deficits of 9 Tcf by 1980 and 17 Tcf by 1990 will become painfully true.[30]

[2654]

The magnitude of the drilling effort which will be required to elicit the supply of natural gas necessary to fulfill reasonable future demands is staggering. It is estimated that annual findings in the range of 37 trillion cubic feet will be required to meet the demand:

> If we assume that an adequate reserves to production ratio of about 10 is maintained; that a reasonably optimistic development of supplemental gas sources is attained with respect to overland imports, LNG imports, gas from coal, and gas from Alaska;

29. Production has exceeded annual reserve additions for every year since 1967. (*See* Table 1, *supra* p. 17) and reserve additions for 1973 were the lowest reported since the American Gas Association first published its report in 1946.

30. Federal Power Commission, Bureau of Natural Gas, *National Gas Supply and Demand 1971-1990—Staff Report No. 2*, p. 1, February 1972.

> that the industry is capable of immediately mounting an all-out exploration and development program unimpeded by financial, equipment or manpower considerations; then an annual finding rate of approximately 37 trillion cubic feet per year would be necessary to bring supply and demand into balance. While this rate of resource development does not include an allowance for the unknown impact of higher gas prices on demand, it is nonetheless sobering to realize that this level of development represents a sustained level of annual additions to reserves equal to that attained in 1970 when 26 trillion cubic feet of Alaskan gas were added to the reserve inventory, or an amount equal to 1½ times the all-time record annual lower 48 reserve additions of 24.7 trillion cubic feet reached in 1956. Attainment of this level of resource development would require the cumulative discovery and development of about 666 trillion cubic feet of natural gas to 1990, representing the development of approximately 58 percent of the Nation's total potential gas supply as estimated by the Potential Gas Committee. This rate of development would be required *in conjunction with* the timely development of supplemental gas supplies and would be substantially higher in the absence of such supplemental supply availability.[31]

[2655]

The supplemental gas supplies anticipated in the years 1975, 1980, 1985, and 1990 for this estimate are 1.5 Tcf,

31. Letter from John N. Nassikas (Chairman, Federal Power Commission) to Senator Henry M. Jackson, September 12, 1973. Material quoted is contained in comments of Bureau of Natural Gas on Senate Interior and Insular Affairs Committee Staff Draft, "Policy Issues and Options Affecting Natural Gas."

4.6 Tcf, 7.6 Tcf, and 11.5 Tcf respectively. The individual components of the 1990 supplemental supply are estimated as follows: pipeline imports—1.9 Tcf; LNG imports—4.0 Tcf; high Btu gas from coal—3.3 Tcf; and gas from Alaska—2.3 Tcf.[32]

The magnitude of the exploration and development efforts that will be required to bring forth these volumes of annual additions is further magnified by the fact that with the exception of 1970 and 1956 annual additions over any period of time have been less than two-thirds of the required findings.[33] Thus, if the demand for natural gas is to be fulfilled,[34] the natural gas industry must attain and sustain a findings rate that it has never before with one exception attained. Whether or not this level of reserve additions can be attained and maintained is a question that can be answered only with the passage of time. It is clear, however, that massive capital commitments will be called for to finance the exploration and development programs necessary to find and produce the supplies so as to fulfill the projected demand.

[2656]

The Commission's regulatory obligation is to establish a uniform national rate in this proceeding that provides

32. Federal Power Commission Bureau of Natural Gas, *National Gas Supply And Demand 1971-1990, Staff Report No. 2*, p. 136 (Table 20) (1972).

These supply levels are based upon an annual demand of 46.4 Tcf and assume that domestic reserve additions will be sufficient to fulfill all demand that is not fulfilled by the supplemental supplies and replenish the nation's inventory of reserves such that the reserves remaining at the year end are ten times the annual production.

33. American Gas Association, *Gas Supply Review Supplement*, p. 2 (Table 1) (May 15, 1974).

34. *See* n. 30 *supra*, p. 136 (Table 20).

the incentives to stimulate and encourage the unprecedented exploration and development efforts that will be necessary to find and produce the requisite level of new natural gas supplies. We further seek to reduce the existing disparity between supply and demand, to effect a more efficient allocation of our existing natural gas resources to higher priority uses, and to encourage the conservation of the limited natural gas reserves which are available to us.

[2657]

2. QUANTIFYING THE SUPPLY-PRICE RELATIONSHIP

While the efficacy of producer rate regulation would be greatly enhanced if it were possible to quantify the amount of reserves that would be forthcoming at a given rate level, it is generally conceded that there is no reliable method by which this quantification can be made.[35] The supply-price relationship has been given extensive attention in several area rate proceedings. In the first Permian Basin area rate proceeding, the Commission noted the emerging price-supply relationship:

> [T]he emergence of directionality, *i.e.*, the ability of producers to direct their drilling activities toward either oil or gas brings in to being for the first time an opportunity for price to play a significant role in increasing the supply of gas-well gas available to the interstate market.

35. *Cf. Public Service Commission For The State Of New York v. FPC*, ____U.S. App. D.C.____, 487 F.2d 1043 at 1089-1090, 1095-1099 (D.C. Cir. 1973), *cert. granted, vacated* and *remanded*, Nos. 73-966, *et al.*, June 17, 1974.

Area Rate Proceeding (Permian Bain), 34 F.P.C. 159, 184 (1965). This proceeding also saw the first econometric studies of the gas producing industry which the Commission viewed as "indicat[ing] that advanced statistical and mathematical techniques can be useful in understanding the interaction of the price of gas at the wellhead and the demand in the marketplace." 34 F.P.C. 159 at 187. However, this first model was "based on a nondirectional hypothesis", and "a materially different equation would [have been] required" if a directional hypothesis had been used. 34 F.P.C. 159 at 332 (Initial Decision Of The Presiding Examiner). Because of these shortcomings, the econometric study did not play a role in the Commission's decision.

In the first Southern Louisiana Area Rate Proceeding, the Commission and the Hearing Examiner had before them a new econometric study which was also found to be unreliable. The utility and accuracy of this new econometric model was viewed in the following manner:

[2658]

> [W]e do not claim that the efficiency of producer regulation cannot be improved with the aid of econometrics and other analytical tools . . . . Should the industry as well as the Staff find it possible to pursue similarly innovative analytical efforts in the years ahead, more reliable results may well be achieved and the regulatory process will be benefitted.

Area Rate Proceeding (Southern Louisiana Area), 40 F.P.C. 530, 625-626 (1968).[36]

36. With respect to this model, the Presiding Hearing Examiner noted:

It might be properly suggested that enough has already been demonstrated to indicate that econometric studies ultimately, on the basis of still further study and improvement by the Staff, may one day be brought to the point where they will provide a significant, useful and reliable tool in this connection. . . . However, it must be concluded on the basis of the record made in the instant proceeding that the econometric presentation here made by the Staff has not yet reached the level where it can safely be relied upon as a basis for the Commission's critical conclusions in this case.

40 F.P.C. 530 at 871-872 (Initial Decision of the Presiding Hearing Examiner).

The latest econometric model to be presented to the Commission was introduced by the Staff in the second Southern Louisiana Area Rate Proceeding and was again found to be lacking as an evidentiary basis for determining supply elasticity:

> [T]he model provides an analytical format for the application of judgment in a more systematic fashion, and it is useful, in a general way, for testing the judgments implicit in this decision. The Commission . . . interprets the model not as a formula to obtain precise quantification of the
>
> [2659]
>
> future supply response to prices—an impossible objective by any method in our view—but as an instructive experimental effort, complementing other exhibits and testimony upon which we may rely for our specific findings and conclusion.

Area Rate Proceeding, et al. (Southern Louisiana Area), 46 F.P.C. 86, 123 (1971).

In this same proceeding, the Commission found that:

> The response of the natural gas industry to the price of the gas, whether that price is fixed by the FPC

> or by other market forces, can only be predicted by assuming that a great number of other factors are going to remain constant. There is no way for any record to prove that such will be the case, and at this moment in history there is every reason to assume that such assumptions are not even much good for the making of academic studies. The area is judgmental in the extreme.
>
> [P]rogress is being made in devising techniques for extrapolating the trends evident from market and investment performance in the past into useful guides for determining what regulators should do in fixing prices or other matter to control future conduct.

46 F.P.C. 86 at 120-121. These findings formed the basis for the Commission's conclusion that there was a positive relationship between the price of gas and exploratory effort, but that:

> the conventional concept of supply elasticity—commonly defined as the quantities which would be forthcoming at a given time at a particular price—is a concept exceedingly difficult to apply to natural gas. The many variables other than price, such as technology and cost of input resources, cannot be readily ascertained.

46 F.P.C. 86 at 121.

[2660]

The Commission then concluded:

> Summarizing, there exists a positive relationship between gas contract price levels and exploratory effort; no reliable quantitative forecasts may be made by increments of additional gas supply resulting

> from specific increased gas prices; increases in ceiling prices which yield increases in producer revenues will result in expanded gas exploratory activity in terms of sufficiency of gas supply in relation to gas demands must be determined by continued Commission observation of the results of our decisions.

46 F.P.C. 86 at 124.[37]

These conclusions are still valid. While further quantitative studies of the elasticity of gas supply with respect to the wellhead price should be encouraged, this case must be decided upon the record that is before the Commission,[38] and the experience gained from previous considerations of this

[2661]

question demonstrates that reliable quantification is not possible with the present state of the art.[39]

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37. In its affirmance of the Commission's decision in the second Southern Louisiana Area Rate Proceeding, the Fifth Circuit reviewed the problems associated with predicting the level of new gas supplies that would be forthcoming at a given rate and stated that "it is impossible with any degree of precision likely to satisfy the momentary opponent's fetish for qualification to determine the likely quantitative effect on supply of a change in the rate ceiling." *Placid Oil Co. et al. v. FPC,* 483 F.2d 880, 901 (5th Cir. 1973) The Supreme Court has agreed with the Commission "that it [the Commission] could not determine the precise amount of additional gas supply that would be found and dedicated to interstate sales as a result of this formula. But this was also true of any change it might have made in gas prices. *Mobil Oil Corp. v. FPC,* 42 U.S.L.W. 4842 (U.S. June 10, 1974) (Slip Opinion at 31). Moreover, the Court found that the Commission's findings were supported by the record (Slip Opinion at p. 32).

38. *Mobil Oil Corp. v. FPC,* ____U.S. App. D.C.____, 483 F.2d 1238 (D.C. Cir. 1973).

39. *See* Foster Associates, Inc., *The Impact Of Deregulation On Natural Gas Prices,* Appendix C (1973), for a discussion of the prob-

The historical record demonstrates in a general manner the responsiveness of gas supply to price. During the 1960's gas prices trended downward, when adjusted for general inflation and gas well exploratory and developmental drilling also turned downward. Toward the end of the decade, the gross annual additions to gas reserves experienced a sharp decline and negative revisions increased sharply.[40] The first signs of a turnaround in drilling activity appeared in 1972, a year or so after the trend of declining real prices for natural gas had been reversed. The number of new gas wells drilled increased 28.7 percent from 1971 to 1972, while the increase in exploratory gas well footage was 38.0 percent. This level of drilling activity continued through 1973; for example, for 1973 exploratory gas well footage increased some 34.8 percent above the level for 1972 and developmental gas-well footage increased by 21.8 percent over the footage drilled

[2662]

in 1972. However, marketed production of natural gas for 1973 showed a decline over 1972.[41] Whether these

lems encountered in the various attempts to develop an econometric model of the supply-price relationship for natural gas and a summary of recent efforts to develop a model.

See also, MacAvoy and Pindyck, "Alternative Regulatory Policies For Dealing With The Natural Gas Shortage," 4 *The Bell Journal of Economics and Management Science* 454 (Autumn 1973); Breyer and MacAvoy, "The Natural Gas Shortage And The Regulation Of Natural Gas Producers," 86 Harv. L. Rev. 941 (1973); MacAvoy, "The Regulation-Induced Shortage Of Natural Gas," 14 *J. Law & Econ.* 167 (1971); Erickson and Spann, "Supply Response In A Regulated Industry: The Case Of Natural Gas," 2 *The Bell Journal Of Economics And Management Science* 94 (1971).

40. *See* Appendix A.

41. FPC Office of Economics, *Gas Supply Indicators — Fourth Quarter, 1973 and Annual Review,* April 1974, p. 6.

increases in drilling activity will bring about an improvement in new additions to natural gas reserves remains to be seen since the reserve additions for 1972 were as the same low level experienced in 1971. (See Appendices A and C (Schedule 2, Sheet 1)). Furthermore, the reserve additions for 1973 were only 6.51 Tcf, the lowest addition reported since the data on reserve additions has been reported. See n. 33 *supra.*

[2663]

Thus, it is concluded that an increase in the price at which natural gas may be sold in the interstate market will have the effect of bringing forth new supplies of natural gas for dedication to the interstate market; however, it is not possible to predict or quantify the precise level of new supplies that will be forthcoming at the rate established herein. To attempt to further define this relationship would be to "demand the perfect at the expense of the achievable."[42]

B. DEMAND

There is little doubt today that the demand for natural gas is far in excess of the available supply and will remain in excess of the available supply for the immediate future.[43] This difference between the available supply

See Appendix C (Statement of J. Rhoads Foster) to the comments filed by the Indicated Producer Respondents for information to the same effect. Chart I in Dr. Foster's statement shows a positive relationship between the initial price for new gas sales and the level of exploratory gas drilling in seven southwestern states for 1947 to 1970.

42. *Public Service Commission For The State of New York v. FPC,* ____U.S. App. D.C.____, 487 F.2d 1043 at 1067 (D.C. Cir. 1973) (Leventhal, J., dissenting).

43. Bureau of Natural Gas, *National Gas Supply and Demand 1971-1990—Staff Report No. 2* (1972).

and the total existing demand constitutes the natural gas shortage. The most direct evidence of this shortage is the continuing curtailment of deliveries by the interstate pipelines.[44]

The pervasive natural gas shortage which we are now enduring has had and will continue to have serious economic consequences for the nation. In Order No. 491 (*supra,* n. 4), the Commission outlined the effect of curtailment of natural gas supply for the major interstate pipelines as follows (*mimeo,* p. 2):

[2664]

> Such curtailments will result, as they did last year, in severe economic and environmental consequences, resulting in the closing of schools, the denial of utility service to new customers, the utilization by industry and electric utilities of alternate fuels which impact upon ambient air quality standards, and the transfer of unfulfilled demand to other fuels in short supply with the resultant upward price pressures.

In Order No. 491-A (*supra,* n. 4), we expanded our analysis of the effects of continued curtailment (*mimeo,* pp. 3-4):

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44. Bureau of Natural Gas, *Staff Report on Interstate Natural Gas Pipeline Curtailments,* FPC Release No. 19640, September 17, 1973.

Hearing on Relationship of Energy and Fuel Storages to the Nation's Internal Development Before the Subcommittee on Flood Control and Internal Development of the House Committee on Public Works, 92d Cong., 2d Sess. 58-9 (1972) (Energy and Fuel Shortages hearings).

See also, Statement of Chairman John N. Nassikas, Federal Power Commission, *Hearing Before the Subcommittee on Activities of Regulatory Agencies of the Select Committee on Small Business,* U. S. House of Representatives, January 17, 1974.

Our staff's revised report indicates (after eliminating inter-company transactions) that eleven of thirty-three reporting companies had experienced curtailments of approximately .4 trillion cubic feet for the period April through October 1972 (summer season). For the same period in 1973, thirteen companies reported actual and estimated curtailments [April through July volumes were actual, whereas August through October volumes were estimated] totaling slightly more than .7 trillion cubic feet. This represents an increase in curtailments of 75 percent over the same period one year ago. Similarly, fifteen companies reported actual curtailments of .4 trillion cubic feet during the period November 1972 through March 1973 (winter season). For the approaching 1973-74 winter season, fourteen companies estimated curtailments totaling approximately .5 trillion cubic feet—an increase of 25 percent. Furthermore, the supply deficiencies for the 1973-74 heating season which were projected in the July 1973 report have substantially increased in the September report. This indicates that the major pipelines are experiencing increasing difficulty in obtaining sufficient gas to maintain reliable service. The following table represents the extent of curtailed service each of the major pipeline companies projects for the 1973-74 season (April 1973 through March 1974):

[2665]

	Firm Requirement Mcf	Volumes Curtailed Mcf	Percent Curtailment
*Algonquin	177,935,800	17,431,500	10.0
Arkansas-Louisiana	495,548,000	119,877,965	24.0
Cities	571,164,000	29,856,000	5.0
Columbia	1,532,573,000	12,574,000	1.0
El Paso	1,906,747,000	147,474,427	8.0
*Louisiana-Nevada	147,271,334	56,700*	Negligible
Mississippi River	209,296,000	7,996,118	4.0
Natural	1,207,139,000	228,868,178*	19.0
Northern	896,000,000	11,800,000	1.0
Panhandle	825,708,000	36,079,308	4.0
Texas Eastern	1,081,814,000	164,503,788	15.0
Transco	1,097,152,000	141,018,748	13.0
Transwestern	360,532,000	20,759,957	6.0
Trunkline	597,986,000	165,601,429	28.0
United Gas	1,602,798,000	541,937,052	34.0

*Summer curtailment only.

> Furthermore, all of the above pipelines, with the exception of Algonquin and Louisiana-Nevada, have been obtaining some gas under the Commission's present emergency purchase provisions. The projected curtailments would thus be even greater without the increments provided by such temporary purchases. [Footnote included in text.][45]

45. An FPC Staff Report issued on June 11, 1974 indicates that natural gas supply deficiencies for the major interstate natural gas companies from the April 1974 through March 1975 period will be nearly 55% higher than a year earlier. The report, by the FPC's

Finally, in Order No. 491-B (*supra,* n. 4), we noted that there was not only a natural gas shortage, but also a national energy emergency (*mimeo,* p. 5):

> In Order No. 491-A, we further observed that problems created by the natural gas shortage are exacerbated by the fact that other fuels, such as propane and fuel oil, are in short supply.

[2667]

We reviewed the problems associated with the short supply of propane and concluded that "curtailments of natural gas this winter will force many industrial plants to operate part-time or shut down completely. Many of these plants could have relied upon propane as a satisfactory alternate fuel." Order No. 491-A, *mimeo,* p. 6. But, we noted that testimony before the September 7, 1973, hearing held by the White House Energy Policy Office indicated that supplies of propane for the 1973-74 heating season would be approximately 15 to 25 percent less than the volumes available during the 1972-73 heating season and that mandatory propane allocations were in force. Order No. 491-B, *mimeo,* p. 5 at n. 7. The short supply of fuel oil available to industrial consumers held out the potential for plant slow-downs or actual shut-downs since neither natural gas nor fuel oil were expected to be available in

Bureau of Natural Gas, based on responses to the Commission's Form 16, shows that actual or projected curtailments were reported by 17 out of 42 major interstate pipeline companies. Net curtailments totaled 1,191,132,000,000 cubic feet for the year April 1973 through March 1974. Net supply deficiencies totaling 1,845,770,000,000 cubic feet are projected for the year April 1974 through March 1975. Cumulative net curtailments of firm service imposed by all companies reporting these data to the Commission since 1970 amounted to approximately 2.4 Tcf through the first quarter of 1974.

sufficient quantities for full industrial operation. *See* Order No. 491-A, *mimeo,* p. 7.

While a mild winter and the fact that greater than anticipated supplies of fuel oil were available have helped to reduce the impact of the shortage of fuels derived from natural gas and crude oil, we find that the nation is still and will continue to be confronted with a national energy emergency resulting from a shortage of basic fuels required to maintain a productive economy. We believe that this continuing energy emergency requires this Commission undertake the establishment of policies that will encourage the development of the additional supplies of natural gas that are needed to fulfill reasonable demands. The promulgation of a single uniform national rate is one of the policies that will help us to increase the available supply of natural gas for the nation.

Much of the demand for natural gas comes not only from its low price, but from its form value[46] and its superior environmental qualities. The present prices for natural gas in relationship to other fuels in the market make it unlikely that increases in the wellhead price of natural gas will have a

[2668]

moderating effect upon the demand for natural gas sufficient to close the supply-demand gap.[47] However, the ultimate consumption of natural gas can be controlled in another fashion. It is possible to regulate energy demand

46. The gaseous form of natural gas facilitates its transportation and delivery to the customer and eliminates the need for storage facilities by the final consumer.

47. Appendix B. See also, Appendix B to the Response of the Indicated Producer Respondents.

met with natural gas to a certain extent by controlling the priority assigned to the end use of natural gas in the consumer marketplace, and requiring that all of the demand assigned to a higher priority is satisfied before new supplies of gas are allowed to be consumed in end uses assigned a lower priority.[48]

The existing demand for natural gas that must be met first is the demand of the homeowner, the small commercial establishment, schools, hospitals, and other consumers that can be classified as "human needs" customers. Quite often, these small consumers are unable to switch to alternate fuels or to use the pollution control devices required when alternate fuels are used to meet air quality standards.[49]

The issue is basically one of the optimum allocation of our limited supplies of natural gas, both now and in the future. Large industrial and utility consumers of natural gas must progressively reduce their use of natural gas to assure its availability to the "human needs" customers. Those users of natural gas who consume the greatest quantities of the very limited

[2669]

supply of this fossil fuel should be encouraged (and re-

48. *Utilization and Conservation of Natural Resources—Natural Gas, "Notice Of Proposed Policy Statement With Request For Comments,"* Docket No. R-467, 38 *Fed. Reg.* 1517 (1973); *Utilization and Conservation of Natural Resources—Natural Gas,* Docket No. R-469, Order No. 467, 49 F.P.C. 85 (1973), Order No. 467-A, 49 F.P.C. 217 (1973), Order No. 467-B, 48 F.P.C. 583 (1973), "Order Denying Motions For Reconsideration, Clarification Or Modification Of Order No. 467-B," 49 F.P.C. 1036 (1973). See Order No. 467-C, 39 *Fed. Reg.* 12984 April 14, 1974.

49. Pollution control devices are more effective when installed on large industrial and utility equipment than when they are installed on heating units in homes and other small consumers of natural gas.

quired, if necessary) to convert to the consumption of other fossil fuels of which there are more abundant supplies. By shifting some demand for natural gas to other fossil fuels, we are able to conserve the available supplies of this precious energy source for consumption in the market sectors where it is both impractical to install and use pollution abatement equipment and uneconomical for the small consumer of natural gas to purchase such equipment.

The existence of the pervasive supply-demand gap requires this Commission to take all reasonable and prudent steps to (1 increase the supplies of natural gas available for resale in the interstate market and (2) allocate the available supplies of natural gas being sold in the interstate market to higher priority uses.[50] As the Supreme Court found in *Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (Slip Opinion at 31-32), there is credible evidence that gas exploratory activities are responsive to price, an increase in the price of gas at the wellhead should encourage greater exploratory activities, and, in turn, make greater quantities of new gas supplies available for resale in the interstate markets. It is also very likely that an increase in the price of natural gas will result in some reallocation of the end use of natural gas in the final market place. However, very little is known about the cross elasticities between the demand

50. The actual allocation of natural gas to its ultimate end uses is within the jurisdiction of the particular state regulatory commission where the interstate pipeline makes deliveries to the local distribution company. However, this Commission has the power to determine which distributors shall be entitled to receive additional supplies of natural gas from the pipeline, and does, therefore, have some indirect power to allocate the ultimate use of natural gas sold in interstate markets. *See* note 48, *supra*.

for natural gas and the demand for other fossil fuels, and it is not possible to accurately predict the results of these reallocations.[51]

[2670]

Although it is unlikely that increases in natural gas prices will dampen demand to the extent of eliminating the supply-demand gap, such increases will encourage a shift to alternative fuels by the industrial and utility sectors of the market place whenever the price of natural gas exceeds the price of other fuels plus the costs of necessary environmental controls. Such a shift, however, is not expected to equal the growing unsatisfied demand for "human needs" customers in the near future.

[2671]

III.

RATE DESIGN

A. *COST FACTORS*

In response to the notice of rulemaking issued in this proceeding on April 11, 1973, and the attached Staff cost studies, the Indicated Producer Respondents (Producers),[52] the GHK Company, the United Distribution Companies (UDC), the Pennzoil Companies, Columbia Gas Transmission Corporation, and the Associated Gas Distributors (AGD) submitted various cost studies or cost analyses. Two of the submitted studies were restricted to certain geographical areas: the GHK study was limited

51. *See*, Department of the Interior, *Draft Environmental Impact Statement—Proposed Deregulation of Natural Gas Prices*, Appendix B, July 17, 1973.

52. The Indicated Producer Respondents is a group of twenty-six major natural gas producers.

to the Deep Anadarko Basin, and the Columbia Gas Transmission Corporation's study reflected the conditions of the Appalachian and Illinois Basin area only. The other studies were based on nationwide cost and drilling data and utilized the procedures adopted by the Commission in Opinion No. 598.[53] The Pennzoil study also referred to the procedures adopted in *Permian I*.[54] AGD suggested a rate of 45.0 cents per Mcf based upon Staff's high cost estimate of 38.5 cents per Mcf with an additional allowance of 6.5 cents per Mcf for increased exploration and development.

In response to the March 21, 1974 notice and the attached Staff cost studies, UDC and GHK submitted new cost studies. The Producers submitted studies which were revisions of their original submittals to reflect full cost accounting and an allowance for Federal income taxes. AGD reiterated its recommendation for a rate of 45.0 cents per Mcf. The details of these studies will be discussed *infra*.

[2672]

Our cost analysis in this decision is based upon the methodology which was developed in the first Permian Basin area rate proceeding, *Area Rate Proceeding, et al. (Permian Basin)*, 34 F.P.C. 159 (1965), *affirmed, Permian Basin Area Rate Cases*, 390 U.S. 747 (1968), and modified in the second Southern Louisiana proceeding, *Area Rate Proceeding, et al. (Southern Louisiana Area)*,

53. *Area Rate Proceeding, et al. (Southern Louisiana Area)*, 46 FPC 86 (1971).

54. *Area Rate Proceeding, et al. (Permian Basin)*, 34 FPC 159 (1965).
The Pennzoil study also reflected full-cost accounting and an allowance for federal income taxes.

46 F.P.C. 86 (1971), *affirmed, Placid Oil Company, et al. v. F.P.C.* 483 F.2d 880 (5th Cir. 1973), *affirmed sub nom. Mobil Oil Corporation, et al. v. F.P.C.*, 42 U.S. L.W. 4842 (U.S. June 10, 1974). Because the costing model relies upon a number of allocations which are based upon flowing gas costs, we shall use the allocation factors which were updated by use of the data submitted to the Commission in response to the questionaire in the second Southern Louisiana proceeding (referred to as the AR69-1 questionaire). This is the most recent information available to the Commission with respect to a number of the allocation factors; however, data submitted to the Commission in the data collection forms which were filed in Docket No. R-478 will help update these factors.[55] When this data becomes available in final form, it will be incorporated into the records of future proceedings to determine national rates so that these allocation factors may be adjusted.

As the Commission has been urged by the Supreme Court to indicate "fully and carefully the methods by which, and the purposes for which, it has chosen to act, as well as its assessment of the consequences of its orders for the character and future development of the industry", *Permian Basin Area Rate Cases, supra*, 390 U.S. at 792, each component of the cost matrix and the methodology used to

[2673]

derive that component will be discussed in detail. We

55. *Nationwide Rulemaking To Establish Just And Reasonable Rates For Natural Gas Produced From Wells Commenced Before January 1, 1973*, Docket No. R-478, 38 *Fed. Reg.* 14295 (1973), "Order Prescribing Further Procedure," 38 *Fed. Reg.* 22898, 50 F.P.C. ____ (issued August 17, 1973).

shall also discuss our reasons for utilizing the particular methodology chosen to derive each of the several components. *See Public Service Commission For the State of New York v. F.P.C.*, 487 F.2d 1043 at 1097-1098 (D.C. Cir. 1973), *cert. granted, vacated* and *remanded*, Nos. 73-966, *et al.*, June 17, 1974.

In making our cost analyses, we present a range of reasonable costs which are based upon that data which we find to be the most reliable data which is now a part of the record to this proceeding or which is contained in the publications that we have incorporated as a part of that record. We shall also discuss the effect of the disparity between the reserve additions reported by the American Gas Association and the reserve additions estimated by our Staff which was reported (and served upon all parties to this proceeding) in our notice of March 21, 1974, in this proceeding,[56] even though the resulting effect is *de minimis* when productivity is averaged over a reasonable time span. A range of "costs" has been presented in this decision to demonstrate that the "cost" of new gas supplies is an imprecise and elusive quantity. There is a "zone of reasonable deviation"[57] in the calculation of the "cost" of

56. 39 *Fed. Reg.* 11310 (March 21, 1974).

57. *Placid Oil Co., et al. v. FPC*, 483 F.2d 880 at 902.
In *Federal Power Commission v. Natural Gas Pipeline Co.*, 315 U.S. 575 (1942), the Supreme Court spoke of "a zone of reasonableness within which the Commission is free to fix a rate varying in amount" (315 U.S. 575 at 585) and the Commission's authority to select its formula of regulation and "to make pragmatic adjustments which may be called for by particular circumstances," 315 U.S. 575 at 586.
In the *Permian Basin Area Rate Cases*, 390 U.S. 757 (1968), the Court spoke of the constitutional and statutory validity of the Commission's determination of maximum prices based upon "group or geographical" data. 390 U.S. 747 at 770. The Court also spoke of the uncertainties associated with the allocation of costs between gas and oil. 390 U.S. 747 at 803-804.

[2674]

new gas supplies, and this "permissible zone of deviation" for costs establishes the reasonable range within which rates may be prescribed.[58]

By presenting a reasonable range of costs, we hope to avoid speculation that the rate determined herein is precise; it is not. As we stated in *Texas Gulf Coast:*

> The cost computations used in this and other area rate proceedings seem to be mathematically precise. They are not. Allocations of costs are by nature matters requiring a substantial amount of judgment.

Area Rate Proceeding, et al. (Texas Gulf Coast), 45 F.P.C. 671, 687 (1971), *reversed, Public Service Commission For The State of New York v. FPC*, 487 F.2d 1043 (D.C. Cir. 1973), *cert. granted, vacated* and *remanded*, Nos. 73-966, *et al.*, June 17, 1974. We recognize the limitations in our ability to reflect actual costs of individual producers in an industry-wide national rate and the futility of attempting to quantify non-cost factors. Instead, we have established a "permissible zone of deviation" for costs. *Placid Oil Company, supra*. The Courts have long recognized that our cost computations and the resulting rate analyses are not precise and have given us the authority to exercise the judgment necessary to determine a "just and reasonable rate" from the morass of conflicting data and presentations that have been introduced in this and the previous area rate cases.[59] It is from this

58. *Placid Oil Co., et al. v. FPC*, 483 F.2d 880 at 902, n. 23.

59. *See Federal Power Commission v. Natural Gas Pipeline Co.*, 315 U.S. 575 at 585 (1942); *Permian Basin Area Rate Cases*, 390 U.S. 747, 824 (1968); *Placid Oil Co., et al. v. FPC*, 483 F.2d 880 at 890-892.

basis that we start our determination of a single uniform national rate in this proceeding.

1. *COST ANALYSIS*

The major variables in a new gas cost study are the drilling costs (cost ($) per foot drilled), productivity (Mcf of gas found per foot drilled), rate of return on investment (percent), the size of the rate base (whether the expenditures for dry holes, other exploration, and exploratory overhead are included in the rate base), and the investment life (years). The final rate further depends upon whether there is sufficient evidence to dictate the inclusion of an allowance for Federal income taxes. Each of these factors will be examined separately before they are combined in the computations of the cost model.

[2675]

a. *Drilling Costs*

All parties submitting cost studies, except Columbia Gas Transmission[60] used 1971 JAS[61] data of $27.64 per foot drilled as a starting point.

60. Columbia Gas Transmission used the Staff cost study in Opinion No. 639 with a productivity of 200 Mcf per foot drilled to reflect its estimate of current costs in the Appalachian Basin Area.

61. *Joint Association Survey of the U.S. Oil & Gas Producing Industry,* 1971 JAS, November 1972, Sponsored by American Petroleum Institute, Independent Petroleum Association of America, Mid-Continent Oil & Gas Association. Hereinafter 1971 JAS.

The basic data sources for drilling and natural gas reserve data are the JAS study, the *World Oil* Annual Forecast-Review issues, the annual report by the American Association of Petroleum Geologists, and the *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972,* Volume 27, May 1973, published jointly by American Gas Association, American Petroleum Institute, and Canadian Petroleum Institute.

These are basic data sources used by the parties to this proceeding, and we shall take official notice of the contents of these reports and comments thereon and identify the sources where necessary.

The Staff cost study did not trend the 1971 JAS data to arrive at a current figure, but both the Producers and UDC studies were trended for inflation. The Producers trended the 1971 data at four (4) percent per year to arrive at a figure of $29.89 per foot drilled for 1973, and UDC trended the same data at five (5) percent per year to arrive at a 1973 figure of $30.47 per foot drilled. Pennzoil arrived at a 1971 cost-per-foot drilled of $38.26 by trending 1967 Bureau of Census data.

Staff adopted the 1971 JAS costs of $15.83 per foot of dry holes drilled, and Producers and UCD trended this figure at four (4) and five (5) percent per year respectively to arrive at costs of $17.12 and $17.45 per foot of dry holes drilled respectively. The Staff cost studies were updated to reflect 1972 JAS drilling cost data and 1972 AGA reserve additions in Revised Appendix B issued with our notice of March 21, 1974 (39 *Fed. Reg.* 11310) in this proceeding.

]2676]

Since the issuance of the original Staff cost study and the submission of cost studies by several of the parties to this proceeding, the JAS report for 1972 (1972 JAS) has been published. That report indicates that the cost of drilling per foot for successful wells has declined slightly since 1971, while the cost of drilling per foot for dry holes increased over the cost per foot reported for 1971. The following table compares 1971 and 1972 drilling costs (excluding data on drilling in Alaska):

Type Of Well Drilled	Cost Per Foot Drilled ($/foot)	
	1971	1972
Gas and Gas Condensate Wells	$27.64	$27.54
Dry Holes	$15.83	$16.94

We have excluded Alaskan drilling data because natural gas reserves located in that state are not now available to supply demands for gas in the lower 48 states.[62] Moreover, as the rate established by this decision will not extend to natural gas produced in Alaska, we have attempted to exclude data on costs incurred in connection with exploratory, drilling, and producing activities in Alaska. The exclusion of cost data relating to Alaskan activities cannot be made complete since costs in a number of categories are reported on a nationwide basis by JAS without any attempt to make a state by state report of these costs. Any error that may result from excluding drilling data for Alaska is offset by excluding reserve additions from Alaska since those additions have tended to show a higher productivity than the national average productivity excluding Alaska over the past several years. Thus, the exclusion of the Alaskan data results in *de minimis* changes

[2677]

in the cost components as will be demonstrated in the sections on the various cost components.

b. *Productivity*

Productivity in terms of Mcf per foot drilled has the most significant impact upon the calculated new gas cost. Because of this impact, a brief overview of the calculation of the productivity figure and the positions of the parties with respect to this factor is warranted.

62. Excluding Alaskan drilling data has only a minor effect on the cost per foot of drilling. Including Alaskan data increases the cost of Gas and Gas Condensate Wells for 1971 and 1972 to $27.70 and $27.78 per foot respectively; the cost of Dry Holes is increased to $16.02 and $17.28 per foot respectively.

The productivity for any one year is calculated by dividing the annual non-associated gas reserve additions as reported by the American Gas Association[63] by the total successful gas footage for that year. There are several sources for the annual successful gas well footage: *World Oil* since 1947, *Oil and Gas Journal* for 1947 to 1965, Joint Association Survey (JAS) starting with 1959, and the American Association of Petroleum Geologists (AAPG) and the American Petroleum Institute (API) reports, both starting with 1965. Over the years, there has been substantial agreement between the JAS, AAPG, and API figures while the World Oil footage figures were either greater than or less than the other reported footage figures by about four (4) to five (5) percent.

The practice adopted in earlier area rate opinions was to average the reserve additions and the successful gas well footage figures over a number of years to determine an average productivity figure that would be used in the calculation of a new gas cost.[64] The magnitude of the productivity calculated by this method depends upon (1) the number of years that are averaged into the calculation, (2) whether *World Oil,* JAS, AAPG, OR API footage is used, and (3) whether the *World Oil,* footage for the years prior to 1966 is adjusted upward on the theory that such footage is understated.

63. *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972,* Volume 27, May 1973, Published jointly by American Gas Association, American Petroleum Institute, and Canadian Petroleum Institute. Hereinafter 1972 AGA Reserve Study.

64. E.g., *Permian Basin Area Rate Proceeding,* 34 FPC 159, 189-192, 377-379 (1965).

[2678]

The Staff used productivity figures of 580 Mcf per foot drilled and 525 Mcf per foot drilled. The 580 Mcf per foot drilled is derived from the ten, fifteen and twenty-five year averages of 588, 576, and 579 Mcf per foot drilled, respectively, utilizing the *World Oil* footages. The 525 Mcf per foot drilled is derived from the AAPG statistics for the six-year period, 1966-1971.

The Producer studies used productivities of 524, 491, and 395 Mcf per foot drilled. The productivities were determined by calculating annual productivities based upon *World Oil* footages, converting the annual productivities to five-year moving averages, and adjusting the moving averages upward by five percent for the claimed understatement of the *World Oil* footages. The productivities of 524, 481, and 395 Mcf per foot drilled are then calculated by averaging the annual productivities for the years 1958 to 1972, 1966 to 1972, and 1968 to 1972, respectively. The Producers state that average historical productivities based upon ten, fifteen, and twenty-five year averages are no longer representative of future projections. The Producers also presented a statistical trend in productivity which tended to show that the average productivity for 1971 to 1975 would be approximately 381 Mcf per foot drilled.[65]

UDC employed productivities of 500 and 350 Mcf per foot drilled. The 500 Mcf per foot productivity is the seven-year average based upon AAPG footage. The 350 Mcf per foot productivity is based upon a four-year average of the same data.

65. See Appendix D of the comments of the Indicated Producer Respondents.

The Public Service Commission for the State of New York states that the Staff's low productivity of 525 Mcf per foot is weighted heavily by the atypical experience of the recent past when there was considerable exploratory and developmental drilling in the offshore Gulf of Mexico areas that has not as yet been reflected in the AGA reserve reports.

The American Public Gas Association stated that the necessary data concerning recent reserve additions are not reflected in the published reports and the extraordinarily low productivity figures for recent years are of no value in estimating the cost of new gas supplies.

[2679]

In the absence of reliable productivity data for the most recent years, AGD's position is that Staff's productivity estimates should be adopted.

GHK uses the Staff's productivity estimate of 580 Mcf per foot drilled for its deep Anadarko Basin study.

Columbia Gas Transmission uses a productivity estimate to 200 Mcf per foot drilled in its study of the cost of new gas supplies in the Appalachian Illinois Basin Area.

On March 21, 1974, we issued a Staff report which indicates that significant new discoveries of non-associated gas reserves reported by AGA for the Southern Louisiana area for 1971 and 1972 are approximately 1.7 Tcf less than our Staff's estimate for the non-associated natural gas reserve additions for 31 selected leases which were sold in the December 1970 lease sale (Notice of March 21, 1974, Appendix B-1, *mimeo,* p. 1). While this disparity may be due simply to a reporting lag by AGA (Notice of March 21, 1974, Appendix B-1, *mimeo,* p. 8),

it is also possible that AGA does not have complete access to the subsurface data necessary to estimate new reserve additions for all areas and that its report is less than complete.[66]

The revised Staff cost studies accompanying the March 21, 1974, notice were based upon productivity factors which range from a low of 336 Mcf per foot drilled (average for 1969 through 1972) to a high of 580 Mcf per foot drilled (average for 1947 through 1971). Additional studies were based upon 552 Mcf per foot drilled (ten year average for 1963 through 1972), 559 Mcf per foot drilled (average of the eleven year (1962-1972) sixteen year (1957-1972), and

[2680]

twenty-six year (1947-1972) periods), a six year period ending in 1971 with a productivity of 525 Mcf per foot drilled, and a 485 Mcf per foot drilled productivity for 1966 through 1972.

UDC submitted revised cost studies in response to this notice and utilized productivities of 400 Mcf per foot drilled with projected drilling costs and 350 Mcf per foot drilled with 1972 drilling costs.

In its comments filed with respect to the March 21, 1974, notice in this proceeding, GHK submitted additional deep drilling cost studies based upon productivities of 552, 1,000, 1,200, 1,333, 1,666, and 2,000 Mcf per foot drilled. GHK used both its own drilling cost experience and 1972 JAS cost data to derive its cost studies.

66. *See* Notice of March 21, 1974, *mimeo*, pp. 3-5; Appendix B-1, *mimeo*, pp. 4-7.

With the exception of UDC and GHK, no parties to this proceeding submitted any mathematical analysis of anticipated future productivity levels in response to the March 31, 1974, notice. The Producers were content to criticize the Staff report indicating a disparity between reserve additions as reported by AGA and the Staff's estimate of the volume of reserves underlying selected leases in the offshore Southern Louisiana area.

While criticism of the Staff report may have been appropriate, the critiques submitted did not rebut the basic finding of the Staff report that there is a disparity between the Staff's reserve study and reserve additions reported by the AGA. Indeed, it seems as though the Producers and the AGA would prefer to ignore the disparity rather than resolving the matter. Representatives of the AGA and certain of the Producer respondents to this proceeding were unwilling to attempt to devise procedures whereby the AGA and Producers would have access to the Staff's data and the Staff would have access to the AGA's data at the conference held in this proceeding on April 16, 1974 (Tr. 9-10, 54-56, 60-62, 69).

[2681]

It is apparent that the AGA would like to have access to the Staff's data without allowing the Staff to have access to the AGA data. Tr. 9, 54-56, 60-62, 69. We do not believe that that is the proper method for resolving this problem. Both sides must have access to the other's data so that meaningful comparisons can be made by both. Therefore, unless and until the AGA is willing to agree to procedures for the exchange of data, we are compelled to find that the reserve additions as reported by the AGA for 1971 and 1972 are understated by ap-

proximately 1.7 Tcf and we shall make the appropriate adjustments to our cost computations.

A different sort of criticism was expressed by UDC. UDC alleged that the Staff's report could not be used to adjust the productivity calculations since the drilling footage required to find and produce these reserves had not yet been reported. The thrust of UDC's agreement regarding drilling footage not being reported is refuted by statements of the AGA representatives at the April 16, 1974, conference (Tr. 53-54) and the filings of the Producers on May 7, 1974.[67] The AGA representatives stated on the record that they were not concerned with drilling footage when they made their annual reserve report.

It is the basic premise of UDC argument that is in error. That premise is that all of the drilling footage associated with the reserves reported for that year is also reported and that there is a correlation between the drilling footage reported in a given year and the reserves reported for that year. While it has been the practice for many years to so calculate an annual productivity, the practice does not refute the Staff's findings that there is a disparity. At best, this argument obfuscates rather than resolves the issue.

[2682]

Moreover, we find no basis in UDC's comments for calculating an annual productivity for a given year by dividing reserve additions for that year by drilling footage for the prior year. Such a procedure implies that we know

67. See "Joint Comments of Indicated Producer Respondents," filed May 7, 1974, Appendix H (pp. 8-9).

for certain that there is a lag between the reporting of drilling footage and reserve additions and that the lag is exactly one year. We find no data in UDC's comments or any of the other parts of the record of this proceeding that support such an adjustment to the productivity. If there is a lag between the reporting of drilling footage and reserve additions, the most effective manner of resolving the problem is to calculate an average productivity based upon a number of years rather than attempting to guess at the length of the lag.

The Associated Gas Distributors (AGD) would have us compute a productivity factor by using a period of time from 1952 through 1967. AGD alleges that such a calculation is required by the low level of exploration following World War II and the unreliability of reserve data for the most recent five or six years. AGD also lagged drilling footage by two years to reflect the development period associated with new reserve additions. We find no basis for totally disregarding the reported reserve additions for 1968 through 1973, and we have previously indicated our reluctance to lag reserve additions and drilling footage. Thus, there is no reasonably reliable basis for AGD's productivity calculation and we reject the same.

The Staff's report of a disparity in reserve additions reported by the AGA and the comments submitted in response to that report reinforce our conclusions that using only the most recent data on reserve additions in a short time period of four years is unreliable, with or without negative revisions, and should not be the primary basis for our decision in this proceeding. We shall, instead, rely upon reserve additions

[2683]

for the most recent ten year period (1963-1972) to compute the law end of the reasonable cost range and the most recent seven years (1966-1972) to compute the high end of this range.[68] This time span is of sufficient length to insure that a reporting lag or the lack of the information required to make a reserve estimate in any given year will not unduly influence the end result while at the same time giving the requisite consideration to the more recent industry experience in finding new supplies of non-associated and associated natural gas.

[2684]

There has been a steady decline in reserve additions, and, in turn, productivity in recent years. A significant factor in that decline is the sharp increase in net negative revisions[69] to existing non-associated natural gas reserves that was first reported in 1969 and which has continued

68. In the *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968), the Supreme Court stated "[t]he Commission's responsibilities necessarily oblige it to give continuing attention to values that may be reflected only imperfectly by producers' costs; a regulatory method that excluded as immaterial all but current or projected costs could not properly serve the consumer interests placed under the Commission's protection." 390 U.S. at 815.

69. Revisions to existing natural gas reserves may be positive or negative. The revisions for fields in a state or sub-area of a state are summed to arrive at a net revision for that sub-area or state. In turn, the revisions for all states are summed to arrive at the total revisions for the year. It is this figure which may be a net positive or a net negative figure, that is reported by the AGA as the annual revisions. See *Reserves of Crude Oil, Natural Gas Liquids, And Natural Gas In The United States And Canada And United States Productive Capacity As Of December 31, 1972,* Volume 27, Published jointly by the American Gas Association, American Petroleum Institute, and the Canadian Petroleum Institute (May 1973).

to this day.[70] This sharp increase in net negative revisions has decreased the net annual additions to the nation's total natural gas reserves. These net negative revisions also reduce the productivity factor for that year even though the revisions may be adjustments to reserves discovered many years prior to the year in which the revisions are reported. Since the revisions are not reported in a manner which would enable us to determine which, if any, of the reported revisions should be used in computing current costs, we find it necessary to use an average productivity based upon a number of years to reduce the impact of such changes on our cost computations. For example, if revisions are made to reserves discovered in 1940, those revisions will not affect the current cost of finding new

[2685]

gas supplies; however, if revisions are made to reserves discovered and reported during the time span which is used to calculate a productivity factor in this proceeding, those revisions would be material and relevant to our determination of a productivity factor in this proceeding. We conclude, therefore, that the utilization of only the reserve additions for the most recent four or five years to determine a productivity factor for the high side of the reasonable cost range would produce a result that is not within the "zone of reasonableness" and that a seven to ten year time period is the appropriate time period to determine productivity factors to compute the reasonable cost range.[71]

70. Appendix A. Revisions and Extensions were first reported as separate classifications by AGA in 1966 so it is impossible to determine a trend in revisions over any significant time span.

71. *Accord, Permian Basin Area Rate Cases,* 390 U.S. 747, 815 (1968).

We have weighted our productivity factors for the reasonable cost range in favor of the recent downward trend in productivity to insure that rate derived from the cost of new gas supplies will be sufficient to encourage the exploration for and development of more marginal gas reserves and to account for the fact that the data for past four years seems to indicate that there has been a definite decline in the industry's ability to find sufficient supplies of natural gas for the nation. The Commission has previously recognized that productivity trends would depend upon "whether the 'dwindling resource' effect, or the improved technology will dominate for the future. If the former, productivity over time will decline; if the latter, it may increase."[72] While one or two years of low productivity would not be indicative of the "dwindling resource effect", the data for the past four years shows not only an increase in negative revisions but also a decline in the other components of the total reserve additions. There are, however, indications that the bleak picture with respect to the reserve additions for the most recent years may not be as hopeless as the reported data would indicate. Appendix B-1 to the March 21, 1974, notice in this proceeding indicates that

[2686]

the reported reserve additions for 1971 and 1972 may be understated by 1.7 Tcf or more. This indicated understatement may be even greater when one considers that the 1.7 Tcf disparity is based upon the difference between the Bureau of Natural Gas' estimate of nonassociated natural gas reserve additions for 1971 and 1972 with

72. *Area Rate Proceeding, et al. (Southern Louisiana),* 46 F.P.C. 86, 130 (1971).

respect to 31 selected leases and AGA's estimate of significant new discoveries for 1971 and 1972 in the Offshore Southern Louisiana area.

The 1.7 Tcf disparity reported by our Staff for 1971 and 1972 is to be contrasted with reserve additions for 1973 which were the lowest ever reported by the AGA. Again, as is the case for most of the recent years, the low level of the additions was in part due to net negative revisions.[73] Other components of the total reserve additions were also at fairly low levels indicating a continuation of the trends observed in recent years.

[2687]

The year-to-year variation in the productivity series over the 1947-1972 period is illustrated in Chart I. In addition to the actual annual data, represented by solid line on the chart, we show a second series, represented by the broken line, which is calculated from the 3-year moving averages of footage drilled and reserves added. The use of moving averages helps to correct for the known time lag between drilling and discovery of reserves. Even though the second series is less volatile than the first, it also indicates substantial cyclical variations. It is especially significant that the date prior to 1969 do not show any consistent upward or downward trend in productivity. There was a strong upward trend from 1960 to 1966 and an even sharper decline thereafter.[74]

Because of the observed instability in year-to-year productivity, the use of short-run productivity data would

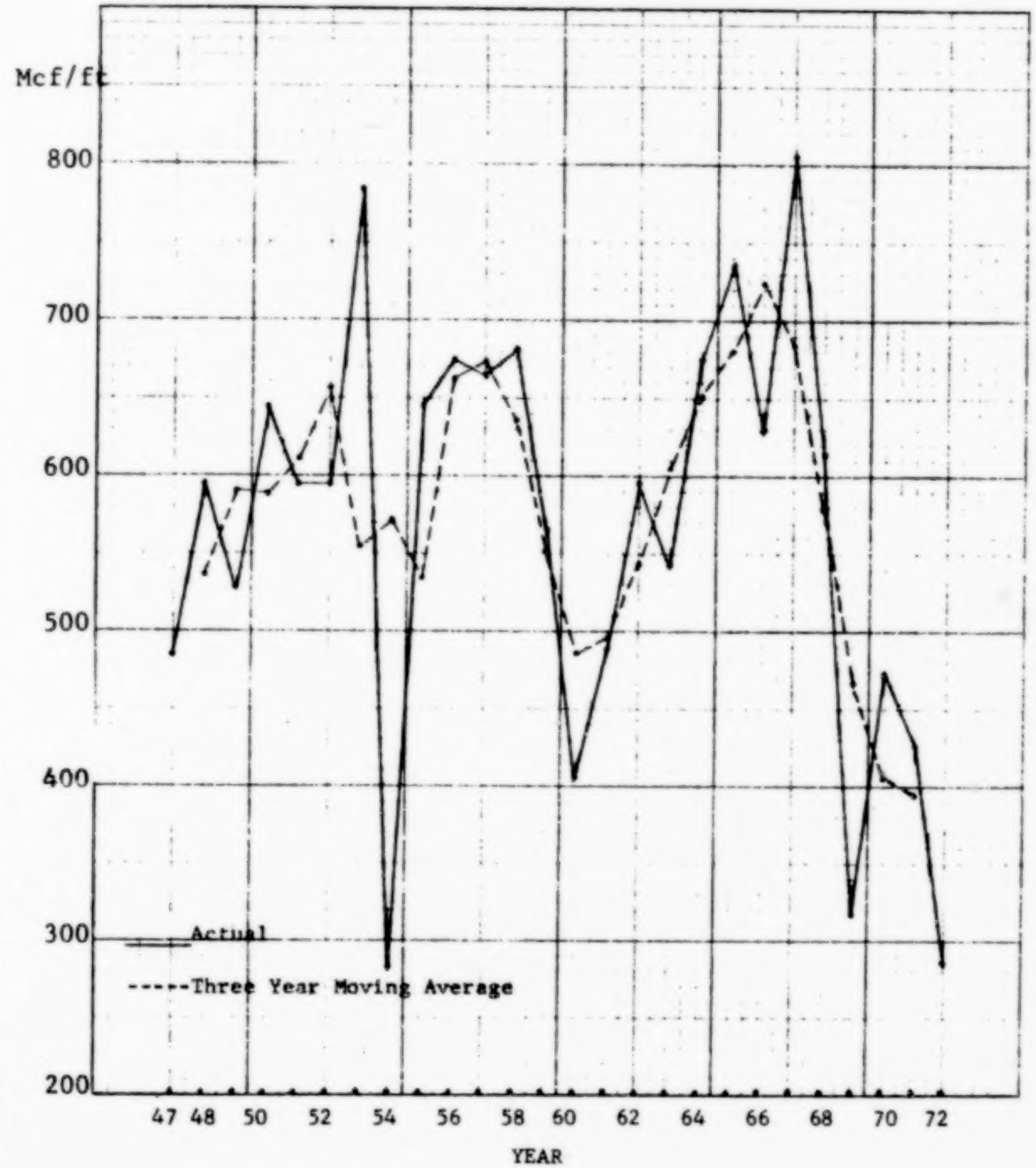
73. See n. 33, *supra* p. 23. The net negative revisions reported in 1973 totaled 5.3 Tcf.

74. *See Also,* Appendix C (Schedule 2, Sheet 2 of 3).

incur the risk of injecting comparable instability in our rate determinations. For example, if in an earlier period we had used the years 1960-1963, our rate determination would have been based on an average productivity of 509 Mcf per foot drilled. If we had then reviewed the rate 4 years later, using the 1964-1967 period, the rate would have been based on 712 Mcf. The increase between the two 4-year periods would have required a substantial downward revision in the rate. Updating to the next 4 years, 1968-1971, would have resulted in a large upward revision in the prescribed rate, since the 1968-1971 productivity was 458 Mcf per foot drilled. We believe that the rate instability that would follow from rates based on short-run productivity would have an adverse effect on future gas supply.

On the other hand, we cannot be confident of an early reversal of the recent years of exceptionally low productivity, even though it has no previous parallel in the industry's history. So that the latest results may be reflected in the rate determined herein while, at the same time, insuring

CHART I
NON-ASSOCIATED GAS RESERVES ADDITIONS PER FOOT DRILLED
IN WELLS PRODUCTIVE OF GAS AND CONDENSATE
UNITED STATES EXCLUDING ALASKA, 1947 - 1972



[2689]

that any given year will not unduly influence the end result, data for the past seven years (1966-1972, inclusive) and AAPG drilling footage have been utilized to determine the productivity for the high cost estimate, and a ten year period (1963-1972, inclusive) and *World Oil* drilling footages have been used to compute the productivity for the low cost estimate.[75] The productivities determined by these methods are 485 Mcf per foot drilled and 552 Mcf per foot drilled, respectively.[76] Adjustment of these productivities to account for the disparity of 1.7 Tcf reported in our notice of March 21, 1974, in this proceeding yields a productivity factor of 559 Mcf per foot drilled for the low side productivity factor. The high side productivity factor is 494 Mcf per foot drilled based upon reserve additions for seven years and AAPG drilling footages.

[2690]

Rates based upon a productivity factor range of 485 Mcf per foot to 559 Mcf per foot provide an incentive to producers to develop more marginal prospects that were formerly passed over as uneconomical. A lowering of productivity increases the rate allowed for new gas supplies which, in turn, makes higher cost developments more attractive and helps offset the higher unit costs associated with gas supplies produced from reservoirs evidencing a low productivity. If we are to reduce the existing gap between the supply of natural gas and the

75. See Appendix C, Schedule 2, Sheet 3 of 3 for the productivity computations.

76. See Appendix C (Schedule No. 1, Sheet 1) for the effect of productivity on the range of estimated new gas costs.

reasonable demand for natural gas, all reservoirs practicably capable of producing commercial quantities of natural gas, not just the most prolific, must be found and developed. Thus, our estimated cost must reflect the inclusion of these less prolific reserves, and the limits of the productivity range must be adjusted accordingly.

The productivity chosen can also serve an eliciting function. Lowering the productivity changes the mix of reserve additions by recognizing the less prolific reserves as a greater portion of the total gas supply. Increasing the productivity has the converse effect of exluding the less prolific reserves from the total mix. In a time of gas shortages, it is neither reasonable nor provident to maintain a high productivity which has the resulting effect of discouraging the development of less prolific reserves. Indeed, it is doubted that the development of the less prolific reserves should be discouraged under any conditions of gas undersupply or oversupply. The most appropriate means of encouraging the development of the less prolific and more costly reservoirs is to decrease the productivity factor so as to reflect the inclusion of the reservoirs in the total mix of reservoirs used to compute the productivity factor.

[2691]

Thus, we have concluded that a productivity range of 485 Mcf per foot to 559 Mcf per foot may be used to calculate the estimated cost of new natural gas supplies in this proceeding.[77] We find that the productivity level which should be realized in the period of 1973 to 1975 is within this reasonable range of productivities.

77. For purposes of the component by component cost analysis, we shall use the unadjusted AGA reserve additions and simply summarize the cost results for the adjusted reserve additions.

c. *Rate of Return*

All parties submitting cost studies in response to the notice of rulemaking issued on April 11, 1973, utilized a 15 percent rate of return.[78] The Producers argued that 15 percent is not "adequate to compensate for the risk of exploration and production."[79] The Producers' comment that 15 percent was not "adequate" was not supported by any data in support of a higher rate of return beyond reference to the testimony of Dr. Ezra Solomon in Docket No. AR69-1.

In response to our notice of March 21, 1974, the Producers submitted comments of Dr. Ezra Solomon and Mr. Kenneth E. Hill which recommended a 15 to 18 percent rate of return computed on a discounted cash flow basis (DCF) after estimated Federal income taxes and based upon "full cost accounting."[80] UDC submitted comments utilizing an 18 percent rate of return; no basis for the 18 percent rate of return was set forth in UDC's comments.

[2692]

GHK in its reply comments suggested up to a 33 percent rate of return for super deep drilling because of the high costs and risks associated with such drilling.[81]

78. UDC used a 16 percent rate of return for its high cost estimate.

79. Indicated Producer Response, Appendix B, p. 3.

80. Comments of Indicated Producer Respondents, filed May 7, 1974, Appendices A and B.

81. Because of our disposition of the question of additional cost allowances for super deep drilling (Super deep wells is a term used to refer to wells with a total depth in excess of 15,000 feet.), we do not find it necessary to consider GHK's rate of return recommendations at this time.

The rate of return allowed in the various area rate proceedings has increased over the years as the result of changing economic conditions. A 12 percent rate of return was found to be adequate in the first two area rate opinion.[82] The higher cost of capital and the need for additional incentives to encourage greater investment in exploration and development programs resulted in a 15 percent rate of return being allowed in the most recent area rate opinions. *See* n. 84, *infra*.[83]

The 15 percent rate of return was approved in the most recent area rate proceedings as within a zone of "reasonableness" and as being "just and reasonable."[84]

[2693]

Current data (See Appendix E) indicate that the permissible "zone of reasonableness" for the rate of return ranges from 12 percent to 15 percent with the high end of the range the most appropriate level for utilization in this decision. *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585 (1942). The high level of the permissible zone is selected because it provides the extra incentive needed to stimulate increased exploration and development activity. Upon careful consideration of all issues pertaining to the appropriate level for the rate of return (*i.e.*, capital requirements, comparable earnings of other investments

82. *Area Rate Proceeding, et al. (Permian Basin)*, 34 F.P.C. 159, 204 (1965); *Area Rate Proceeding, et al. (Southern Louisiana Area)*, 40 F.P.C. 530, 7576 (1968).

83. The rates approved for the Other Southwest Area track the rates approved in *Southern Louisiana II* and *Texas Gulf Coast* which were based upon a 15 percent rate of return. *Area Rate Proceeding, et al. (Other Southwest Area)*, 46 F.P.C. 900 (1971).

84. 45 F.P.C. 674, 698-9; 46 F.P.C. 86, 131; *Area Rate Proceeding (Permian Basin Area II)*, Docket No. AR70-1 (Phase I), Initial Decision, *mimeo*, pp. 31-32.

with commensurate risk, and gas supply and demand), we find that the high level of the reasonable range for the rate of return (15 percent) should be adopted in this decision.

We find no reliable evidence supporting a rate of return greater than 15 percent. This rate of return compares favorably with the returns earned by other extractive industries, utility companies, industrial concerns, and the overall earnings of large integrated producers and the predominately pure producer. These integrated oil and gas companies exhibit many of the same characteristics of the pure producer and have many of the same risks. Thus, we find 15 percent to be a generous rate of return using comparable earnings as a guide. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 697 (1923); *FPC v. Hope Natural Gas Company,* 320 U.S. 591 (1944).

The question at issue is whether the 15 percent rate of return on total investment (which yields a return of over 17 percent on equity) is still appropriate in setting a nationwide rate in light of current and prospective economic conditions for the petroleum industry.

In our consideration of the fairness of this return, we have relied primarily on the comparative approach which is based on the opportunity cost of capital concept. In essence, this concept professes that for any potential investment the capital must be compensated according to the risks involved or else it will flow to alternative opportunities in the marketplace offering returns commensurate with the risk such capital is willing to assume. This approach is consistent with "comparable earnings" test in the *Bluefield* and *Hope* cases, *supra,* in that we

have considered the rates of return new capital could earn in alternative investments in addition to the returns on average investment capital.

[2694]

In implementing this approach, we examined the returns earned by a cross-section of American industry involving different degrees of risk. Appendix E, Sheet 1, shows that such returns have ranged between 10.8 percent and 11.6 percent during the five years 1968-1972. In 1972 alone, such returns ranged between 4.3 percent and 17.7 percent and averaged 10.3 percent, as shown on Sheet 2 of Appendix E.

Furthermore, we appraised the returns realized on total capital by oil companies, primarily integrated oil companies, since few companies except the very small enterprises are any longer strictly producers. Sheet 3 of Appendix E shows that the returns on total capital realized by a cross-section of oil and gas producing companies during the year 1971 and 1972 averaged approximately 8.5 percent. It should be recognized that there are difficult allocation problems in determining the relative returns on capital invested in the production of natural gas and crude oil. We believe that the allowance of a 15 percent return on capital invested in the production of natural gas is fair in relation to the overall return on capital experienced by companies engaged in the joint exploration for and production of natural gas and crude oil.

By and large, our study revealed that the 15 percent overall return is high by comparison to the actual average returns realized by most oil companies as well as by most industries on their combined total investment. Similarly, with any degree of leverage in the capital structure, the

returns on equity would be higher than the average returns realized by the oil and gas industry as well as by most other industries on their combined equity capital as follows:

Capital Structure - 1972*

	Million Dollars	Capital Ratios	Costs	Weighted Component
Long-term Debt	$21,858	23.35%	6.25%	1.46
Preferred Stock	404	.43	6.00	.26
Common Equity	71,352	76.22	17.42	13.28
	$93.614	100.00%		15.00%

* Source: Financial Analysis of a Group of Petroleum Companies A Chase Manhattan Bank Study.

[2695]

However, we must consider that any new external capital committed to the exploration and production of natural gas will be acquired at the higher incremental rates presently prevailing thus reducing the benefits of leverage. For example, if in the capital structure above the embedded costs for debt and preferred stock were replaced by recent costs for debt and preferred stock the return on equity would drop to 16.70 percent from 17.42 percent.

Even though this 15 percent return on total capital as well as the equity returns under it are higher than the actual average returns realized by most industries, it may be conservative by comparison to the marginal returns demanded by business on new venture capital. Indeed, in appraising the fairness of the 15 percent return on the risk capital committed to the production of natural gas, it is far more meaningful to compare it with the returns

necessary to attract new venture capital, rather than with the average established returns on combined total investment which involves a lower degree of risk. We have, however, no way of determining the marginal rates of return for new venture capital which are considered the minimum return which must be earned by a new project before funds will be invested. In this respect, we note that the 15 percent rate of return allowed by this order is approximately double the average rate of return earned on total investment capital by a cross-section of the integrated petroleum companies for 1971 and 1972 (Appendix E, Sheet 5). The 15 percent rate of return is also several percentage points higher than the rate of returns earned on average total capital for a number of industrial groups as shown on Sheet 1 of Appendix E. Thus, we find that a 15 percent rate of return is sufficient to attract new capital to natural gas exploration and development for the interstate market.

On that premise, it is our judgment that the 15 percent return is the appropriate incentive rate required to attract the high risk capital to finance the exploration, development, and production programs which must be undertaken to produce the new natural gas supplies necessary to fulfill the existing and future interstate demand.

[2696]

d. *The Rate Base*

This Commission's traditional costing methodology capitalizes the "successful well costs" and expenses the "unsuccessful well costs."[85] This procedure which has

85. The term "successful well costs" is used to refer to the costs of successful wells, recompletions and deeper drilling, lease acquisi-

been followed since the first *Permian* decision[86] has become the subject of considerable questioning by a number of natural gas producers recently, who have urged the Commission to provide a return on the "unsuccessful well costs" under the principles of "full cost accounting." (These principles have also been referred to as a "return on dry hole costs.")[87]

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tions, and other production facilities, and the term "unsuccessful well costs" is used to refer to the costs of dry holes, other exploration, and exploration overhead.

86. 34 F.P.C. 159, 191 (1968).

87. The Pennzoil Companies (Pennzoil Company, Pennzoil Producing Company, Pennzoil Offshore Gas Operations, Inc. (POGO), and Pennzoil Louisiana and Texas Offshore, Inc. (PLATO) urged the Commission to provide such a return in their comments filed in this proceeding on May 16, 1973, and June 1, 1973.

[2697]

The issue of full cost accounting has also been raised in a number of our optional pricing cases:

Barber Oil Exploration, Inc., *et al.* Docket No. CI74-199, *et al.*
C&K Offshore Company (Operator), *et al.* Docket No. CI74-434.
Pennzoil Producing Company and Midwest Oil Corporation
Docket Nos. CI72-321 and CI73-755
Pennzoil Producing Company
Docket No. CI74-244
Pennzoil Company
Docket No. CI74-253
Pennzoil Producing Company
Docket No. CI74-272
Pennzoil Company and Anadarko Production Company
Docket No. CI74-264 and CI74-408
The Rodman Corporation
Docket No. CI73-694
Tenneco Oil Company
Docket No. CI74-132
Tenneco Oil Company
Docket No. CI74-301
Texaco Inc., *et al.*
Docket No. CI74-82, *et al.*

In response to the questions which have been raised concerning our policy of allowing a return only with respect to the "successful well costs" and the need to resolve the issue uniformly rather than on a case-by-case basis, we asked, in our notice of March 21, 1974, whether the principles of full cost accounting should be applied to producer ratemaking or whether the "unsuccessful well costs" should continue to be treated as current expenses for ratemaking purposes. We further raised the question as to the rate of return which would appropriate if full

[2698]

cost accounting were utilized to determine producer rates.[88]

A majority of parties to the rulemaking submitting comments in response to the March 21, 1974, notice on these questions urged that the principles of full cost accounting be adopted in establishing the national rate for natural gas sold in interstate commerce.[89] The parties urging the adoption of full cost accounting were not all in agreement as to the application of full cost accounting. Some parties urged that the rate of return would have to

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88. Notice of March 21, 1974, *mimeo* p. 5, 39 *Fed. Reg.* 11310 (1974).

89. A vast majority of the parties urging the adoption of full cost accounting were natural gas producers. The Indicated Producer Respondents, the Pennzoil Companies, The Rodman Corporation, Tenneco Oil Company, and Texasgulf, Inc., submitted such comments. Columbia Gas Transmission Corporation, the United Distribution Companies, General Motors Corporation, and Arthur Anderson & Co. supported the adoption of full cost accounting.

Northern Natural Gas Company, The Public Service Commission of the State of New York, and the American Public Gas Association opposed the adoption of full cost accounting.

be adjusted downward to reflect the increased rate base,[90] while others opposed such a procedure.[91] The Associated Gas Distributors (AGD) suggested that a rate of return equal to one-half of the return allowed on "successful well costs" be allowed for "unsuccessful well costs."

[2699]

Several parties (the Pennzoil Companies and Tenneco Oil Company) cited Order No. 440[92] in support of their arguments for the adoption of full cost accounting as a ratemaking principle. Such arguments are not compelling since the parties fail to consider and apply the limitations which we set forth in Order Nos. 440 and 440-A. In Order No. 440, we required natural gas pipeline companies subject to the jurisdiction of this Commission to capitalize and write-off over the lives of the productive wells all exploration and development costs incurred with respect to leases acquired on or after October 8, 1969. Full cost accounting was adopted as an accounting method because we believed that it would better match revenues and expenses for accounting reporting purposes.[93] For ratemaking purposes, however, we clearly stated in Order No. 440-A[94] that the pipeline companies required to adopt

90. New York and APGA opposed the adoption of full cost accounting on this basis.

91. Those opposing such a reduction were the Producers and other parties urging the adoption of full cost accounting.

92. *Revisions In Uniform Systems Of Accounts For Natural Gas Companies (Classes A, B, C, and D) And Annual Report Form No. 2 To Adopt Full-Cost Accounting For Exploration And Development Costs Incurred By Pipeline Companies On Natural Gas Leases Acquired On Or After October 8, 1969*, Docket No. R-403, Order No. 440, 46 F.P.C. 1148 (1971), Order No. 440-A, 47 F.P.C. 39 (1972).

93. 46 F.P.C. 1148, 1150 (1971).

94. 47 F.P.C. 39 (1972).

full cost accounting would not receive the applicable area rate for their natural gas production as provided in the Pipeline Area Rate Proceeding[95] and, in

[2700]

addition thereto, receive a return on the costs associated with leases acquired on or after October 8, 1969. Thus, it is clear that Order Nos. 440 and 440-A merely provide for the adoption of full cost accounting as a superior accounting method and not as a ratemaking principle.

There is, however, an even more serious deficiency in the argument that Order No. 440 supports or requires the adoption of full cost accounting in this proceeding. That deficiency is the failure to provide a procedure whereby the capitalized unsuccessful costs may be written-down if they exceed the value of the reserves discovered. The accounting prescribed in Order No. 440 included the unsuccessful costs in the plant accounts, but provided that such costs, after a reasonable time, must not exceed the net realizable value of the recoverable reserves.

In Order No. 440-A[96] and in Order No. 468,[97] we re-

95. *Pipeline Production Area Rate Proceeding (Phase I)*, 42 F.P.C. 738, as amended, 42 F.P.C. 1089 (1972), *affirmed*, *City of Chicago v. F.P.C.*, 147 U.S. App. D.C. 312, 458 F.2d 731 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 1074 (1972).

96. 47 F.P.C. 39, 41-42 (1972).

97. *Revisions In Uniform System Of Accounts, For Natural Gas Companies (Classes A, B, C, and D) And Annual Report Form No. 2 To Provide That The Determination Of Natural Gas Reserves On Acreage Acquired After October 7, 1969, Shall Be Made And Attested To By Independent Appraisers, To Disclose The Net Realizable Value And Related Costs Of Hydrocarbon Reserves, And To Eliminate An Allowance For Equity Funds On Exploration And Development Expenditures Incurred On Or Related To Acreage Acquired After October 7, 1969*, 49 F.P.C. 219, 220-221 (1973).

quired pipelines which are accumulating costs on leases acquired after October 7, 1969, to periodically write down the net book value of the capitalized plant if it is determined that the net realizable value of the reserves underlying the subject leases is less than the net book value. There are no comparable procedures advanced by the Pennzoil Companies or Tenneco Oil Company. For this reason, and because of the nature of the costs, i.e., "unsuccessful,"

[2701]

we are reluctant to treat the unsuccessful costs as investments upon which a return should be allowed. The effect of allowing such a return would be an overstatement of investment base used in computing the return on investment component and the allowance of an excessive rate of return as well as excessive rates.

The fundamental issue, however, seems to be: Should we alter the traditional costing methodology used to establish natural gas rates because of a change in an accounting procedure? We answer the question in the negative. Our basic costing approaches were adopted many years before we adopted full-cost accounting in our Uniform System of Accounts for Natural Gas Companies. The fact that some companies account for unsuccessful costs under the full-cost concept does not lead us to the conclusion that we should alter our basic cost determinations and treat unsuccessful costs as part of the investment base to which a rate of return is applied. The net effect of changing our costing methodology to reflect full-cost accounting would be to increase the return component of the national rate without any change in the cash outlays required by producers or any change in the

risks associated with their investments. Such a procedure could only result in producer profits which are higher than those we have consistently found to be just and reasonable on the basis of traditional costing methodology.

Natural gas producers, unlike public utilities, are not regulated on the basis of a return on their entire investment committed to the enterprise

> "Producers of natural gas cannot usefully be classed as public utilities. They enjoy no franchises or guaranteed areas of service. They are intensely competitive vendors of a wasting commodity they have acquired only by costly and often unrewarded search. Their unit costs may rise or decline with the vagaries of fortune. The value to the public of the services they perform is measured by
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> [2702]
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> the quantity and character of the natural gas they produce, and not by the resources they have expended in its search; the Commission and the consumer alike are concerned principally with 'what [the producer] gets out of the ground, not . . . what he puts into it . . .' *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 649 (separate opinion)."

Permian Basin Area Rate Cases, 390 U.S. 747, 756-757 (1968) (footnote omitted).

The adoption of full cost accounting (or "return on dry hole costs") would drastically reduce the risks involved in the exploration for and production of natural gas and place the Commission in the position of being a guarantor. Production is not riskless and cannot be regulated as such. If producers are to be regulated as

public utilities, they should be regulated as such on a company-by-company basis.

As a minimum, the utilization of full cost accounting (or "return on dry hole costs") would require a reduction in the allowable rate of return since the increase in the investment base upon which a return is allowed is drastically increased. This increase in the investment base results in a much lower investment risk which must be considered in determining the appropriate rate of return which is commensurate with the risk of the enterprise. Under the comparable earnings principles, allowance of the same rate with the utilization of full cost accounting as is allowed under our traditional costing methodology would result in an exorbitant return to natural gas producers. *See Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 697 (1923); *FPC v. Hope Natural Gas Company,* 320 U.S. 591 (1944).

e. *Investment Life*

The average investment life estimates used by the various parties range from nine years to twelve years with the average around 10.5 years. The Commission has

[2703]

determined that a range of 9 to 10.5 years represents the most reasonable allowance for the investment life in light of declining depletion periods and the nation's needs for additional supplies of natural gas.

The Staff recommended an average investment life of nine (9) years including lag time. IPR utilized 11.5 years, and UDC used nine (9) and eleven (11) years. Our

recent area rate decisions have utilized either 10.5 years or 11 years[98] as the appropriate investment life including a time lag between the commitment of funds to acquire the necessary leases and the commencement of revenues at a later date.

We adopt Staff's average investment life of nine (9) years as the basis for determining the depletion period for the range of reasonable costs. *See,* Appendix C (Schedule No. 1 Sheet 2) for our cost analysis based upon a nine year investment life. We are of the opinion, however, that Staff's estimated investment life is understated as a basis for determining reasonable costs. To determine the investment life for the range of reasonable costs, we start with an average depletion period of eighteen (18) years; this yields a depletion period of nine (9) years to be included in the investment life. To this we add a lag period of 1.5 years. *See, Area Rate Proceeding, et al.* (Southern Louisiana Area), 46 F.P.C. 86, 131 (1971). The investment life for the range of reasonable costs is found to be 10.5 years from the foregoing.

[2704]

Our analysis of depletion rates indicates that the nation's present needs for additional supplies of natural gas have caused reservoirs to be depleted at greater rates than in the past. Thus, the twenty (20) year depletion which was the basis for the 11 year investment life in

98. A 10.5 year investment life was utilized in *Area Rate Proceeding (Texas Gulf Coast Area),* 45 F.P.C. 674 (1971); *Area Rate Proceeding (Southern Louisiana Area),* 46 F.P.C. 86 (1971); and *Area Rate Proceeding (Other Southwest Area),* 46 F.P.C. 900 (1971). In *Area Rate Proceeding (Permian Basin Area),* Docket No. AR70-1 (Phase I), 50 F.P.C.____ (issued August 7, 1973), the Commission adopted the Presiding Administrative Law Judge's cost findings which were based upon an 11 year investment life.

the first Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), is no longer appropriate. Furthermore, the use of an eighteen (18) year depletion period might cause this factor to be somewhat overstated. However, the present natural gas shortage requires additional exploration and development programs be undertaken and that reasonable incentives be allowed to encourage the commencement of additional exploratory activity. After consideration of these factors, we believe that the eighteen (18) year depletion period is reasonable and it will be utilized by the Commission to determine the reasonable range for the investment life.

f. *Federal Income Taxes*

In their initial and reply comments filed on May 16, 1973, and June 1, 1973, the Pennzoil Companies urged the Commission to provide an allowance for Federal income taxes based upon hypothetical tax calculations. Similar presentations were made by the Major Producer Group, The Pennzoil Companies, the Rodman Corporation, Tenneco Oil Company, Texasgulf, Inc. in comments filed on May 7, 1974. Mobil Oil Corporation argued that a Federal income tax allowance would be required at the rates generated by its "discounted cash flow" methodology in comments filed on May 29, 1974. Also, in comments filed on May 29, 1974, Texaco, Inc. alleged that a Federal income tax liability would be generated by the rates computed using Texaco's discount cash flow methodology. We are of the opinion that these presentations do not provide a proper basis for computing the Federal income tax component; however, we shall allow any natural gas producer subject to the jurisdiction of this Commission to establish that their particular cir-

cumstances require the grant of special relief in the form of an allowance for Federal income taxes. Persons making

[2705]

such a presentation will be required to introduce into evidence copies of their Federal income tax returns and such supporting schedules as are necessary to permit the Commission to determine the appropriate amount of a Federal income tax allowance, if any.[99]

We find ourselves in agreement with the comments filed by the Associated Gas Distributors (AGD) on May 29, 1974, wherein AGD states that a claim for Federal income taxes should not be considered in the absence of "actual data from the producers' income tax returns, which the producers have been unwilling to provide in" this proceeding. AGD comments of May 29, 1974, p. 7. Contrary to the arguments of some parties,[100] Federal income tax returns are important in the determination of the appropriate Federal income tax allowance for the jurisdictional natural gas operations of a producer seeking such an allowance. The findings on the Federal income tax arguments advanced by the producers in the first Southern Louisiana Area Rate proceeding are appropriate here:

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99. See 26 C.F.R. §§1.611-2(g), 1.613-6; Treas. Reg. §1.611-2(g), T.D. 6446, 1960-1 *Cum. Bull.* 208, amended T.D. 6938, 1968-; I.R.B. 25, and amended T.D. 7170, 1972-17 I.R.B. 12; and Treas. Reg. §1.613-6, T.D. 6446, 1960-1 *Cum. Bull.* 208 amended T.D. 7170, 1972-17 I.R.B. 12; for the supporting schedules to accompany the Federal income tax returns where the petition for special relief is sought because of Federal income taxes payable.

100. *See* comments of the Pennzoil Companies (p. 6) filed May 7, 1974; comments of Tenneco Oil Company (pp. 6-7) filed May 7, 1974.

[2706]

"With respect to income taxes, in order to make a finding that the industry as a whole pays taxes, it is essential in the first instance that we have for analysis a reasonably representative group of income tax returns of the corporate and individual entities constituting the industry. The producers have not chosen to come forward with such a group of income tax returns for the record. Without such returns available to us, we cannot begin the required analysis which will establish the extent of the industry's tax liability if any, in the light of the provisions of the revenue laws which would reduce or eliminate the tax liability. Obviously, evidence in the record that some of the companies or individuals may pay a tax will not suffice. Such evidence does not support a finding that the industry as a whole pays a tax on its gas production operations. Consequently, in view of the lack of record support, we are constrained to find no basis for a determination that a tax liability exists."

Area Rate Proceeding (Southern Louisiana Area) et al., 40 F.P.C. 530, 585-586 (1968), *affirmed Austral Oil Company, et al. v. FPC,* 428 F.2d 407, *reh. denied,* 444 F.2d 125, *cert. denied,* 400 U.S. 950 (1970).

Our decision in *Florida Gas Transmission Company*[101] is consistent with the above position. In that proceeding we held that the rates of a regulated pipeline were not to be reduced because a non-regulated affiliate had a tax

101. 47 F.P.C. 341 (1972), *reh. denied,* 49 F.P.C. 261 (1973), *appeal pending sub nom. Sun Oil Co. v. FPC,* Nos. 73-1203 and 73-1413 (D.C. Cir., filed February 27, 1973).

loss in the test year. Likewise, in this proceeding, we seek to insure that the income tax allowance will be based upon the revenues and deductions generated by the exploration for, production of, and sale of natural gas in interstate commerce. To the extent that taxes are reduced or a net tax benefit arises from the exploration for and subsequent sale of natural gas in interstate commerce, the rates allowed for the sale of such gas should be adjusted accordingly.

[2707]

We believe that there is a potential for Federal Income Tax liability for producers and some producers may be paying taxes; however, under current tax laws, if producers maintain a sufficiently active exploration effort the payment of taxes can be postponed indefinitely into the future. The provisions of the tax laws are such that substantial tax deductions result from producer operations prior to the period that production begins. As indicated in the comments of some of the parties, such tax deductions relate to expensing a portion of exploration expenditures for tax purposes; writing off a portion of lease aquisition expenditures when the leases prove unproductive; expensing 100 percent of the dry holes in the year drilled; writing off the intangible drilling cost portion of the cost of successful wells, and, additionally, the producers generate certain investment tax credits.[102] Upon commencement of production, the producer has statutory depletion available for tax deduction as well as operating expenses and other deductions.[103]

102. *See* Internal Revenue Code of 1954, §§38, 46-50, 263(c); Treas. Regs. §1.612-4 (26 C.F.R. §1.612-4).

103. Internal Revenue Code of 1954, §§162, 164, 611-614.

Upon careful consideration of the various comments filed, the parties' attempts to determine an income tax allowance on a cents per Mcf basis, we find that some correlation between the provisions of the Internal Revenue Code and the cents per Mcf analysis must be presented.

Since any analysis of the need for a Federal income tax allowance must be based upon the relationship between the timing of expenditures and revenues from a particular property, such an allowance cannot be adopted as part of the national rate without an investigation of the tax

[2708]

returns of a representative group of producers. In cases where an individual producer or group of producers seeks special relief because of Federal income taxes payable, we shall require the producer or producers to submit the appropriate tax returns for our consideration. We realize that there may be some difficulty in separating jurisdictional expenditures from non-jurisdictional expenditures, but that is a difficulty which must be accommodated.

Thus, in view of the record available to us, we find that a cost component for Federal Income Taxes should not be included in the national rate. However, we shall consider petitions for extraordinary relief where a producer can affirmatively show that his overall natural gas operations result in the actual payment of Federal Income Taxes.

[2709]

g. *Cost of New Gas*

(1) *Successful Well Costs*

Successful well costs are calculated by dividing the

drilling cost per foot of successful gas wells for a given year (1972 for this decision) by the non-associated gas reserves added per foot drilled over a number of years (Mcf per foot).

The estimates of successful well costs ranged from 4.77 cents per Mcf (Staff's low estimate) to 8.71 cents per Mcf (UDC's high estimate).[104] This range is due primarily to the various parties using different productivities in their cost studies and trending of the 1971 JAS costs for inflation by the Producers and UDC. Restating the cost data and productivities to the bases already adopted by the Commission shows that there would be small differences between the estimates of the parties.

Successful well costs are found to range from 4.99 to 5.68 cents per Mcf based upon 1972 JAS cost data ($27.54 per foot) and productivities equal to 559 and 485 Mcf per foot.[105]

[2710]

A range of successful well costs of 4.99 to 5.68 cents per Mcf is found to be just and reasonable.

(2) *Recompletion and Deeper Drilling*

All parties submitting cost studies adopted 0.20 cents per Mcf as an adequate allowance for the cost of re-

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104. Successful well costs and other components of the GHK and Columbia Gas Transmission studies will not be considered in this general discussion of the cost of new natural gas supplies since they are specialized studies directed to cost of new gas supplies in certain specific areas (the Deep Anadarko Basin and the Appalachian Illinois Basin Area).

105. Inclusion of Alaskan drilling data and reserve additions would yield a successful well cost of 5.51 cents per Mcf based upon the most recent seven-year period.

entering an old well for a recompletion, drilling deeper, or redrilling.

This component was first adopted as a separate part of the cost matrix in the second Permian Basin proceeding.[106] This cost element was first determined to be approximately three to five percent of successful well costs from the responses to the AR69-1 Questionnaire. *See Area Rate Proceeding, et al. (Southern Louisiana Area)*, 46 F.P.C. 86, 131 (1971), for a discussion of this component. This cost is not included in the JAS drilling costs and was derived as a percent of total gas well drilling costs from the responses to the AR69-1 Questionnaire.

As there is no major dispute over the allowance for recompletions and deeper drilling, the Commission will adopt the 0.20 cents per Mcf which was used by all parties submitting cost studies.

(3) *Lease Acquisition Costs*

The lease acquisition cost component is calculated by multiplying the successful well cost by the ratio of national lease acquisition costs divided by national successful well costs.

Staff determined that the ratio to be applied to the successful well costs is 0.6112 based upon JAS data for 1967 to 1971. UDC accepted this ratio. The Producers calculated a ratio of 0.803 utilizing both JAS and Chase Manhattan Bank data. The Producers then adjusted this ratio upward to 0.937

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106. *Area Rate Proceeding (Permian Basin Area)*, Docket No. AR70-1 (Phase I), Opinion No. 662, 50 F.P.C.____ (issued August 7, 1973); see the *Initial Decision, mimeo* p. 37.

[2711]

to reflect their contention that proportionately more of the national lease acquisition costs are incurred by gas leases as compared to oil leases.

Our examination of the method used by the Producers to calculate lease acquisition costs convinces us that it overstates the appropriate allowance for lease acquisition costs and unnecessarily complicates the determination of this component of the cost model. A significant deviation between the method used by Staff and UDC and the method used by the Producers is the allocation of a thirty percent higher ratio of leasehold to drilling costs for gas than for oil leases by the Producers. This thirty percent factor is not derived by the Producers nor supported by any evidence or data in the IPR presentation. We will, therefore, accept the methodology utilized by Staff and UDC to calculate lease acquisition costs.

These computations of lease acquisition costs yield a range of 2.92 cents per Mcf (Staff's low estimate) to 7.09 cents per Mcf (Producer's high estimate). Staff's straight line relationship between lease acquisition costs and successful well costs is accepted.

Because JAS data for 1972 have been reported since the notice of rulemaking was issued in this proceeding and the various parties submitted their cost studies, the Commission has updated Staff's straight line relationship between lease acquisition costs and successful well costs to account for 1972 lease acquisition costs as reported by JAS. As shown in Appendix C (Schedule No. 3), the ratio of lease acquisition costs to successful well costs for 1967 to 1972 inclusive is 0.6740. Application of this ratio to the successful well costs of 4.99 and 5.68 cents

per Mcf yields a lease acquisition cost range of 3.36 to 3.83 cents per Mcf.

Restating the UDC and the Producer calculations to the same data base used in Appendix C of this decision we find that UDC's lease acquisition costs are 3.36 to 3.83 cents per Mcf. Staff's lease acquisition costs are 3.36 to 3.83 cents per Mcf, and the Producer's lease acquistion costs are 4.61 to 5.32 cents per Mcf. The difference between the costs calculated by Staff and UDC and the costs calculated by the Producers is the higher allocation of costs to gas leases adopted by the Producers.

[2712]

The Commission finds that a range of lease acquisition costs 3.36 to 3.83 cents per Mcf should be adopted in this decision.

(4) *Other Production Facilities*

The other production facilities cost component is calculated by multiplying the successful well cost by the ratio of national other production facilities costs divided by national successful well costs. The ratio of national other production facilities to national successful well costs is calculated by adding the cost of other production facilities to the cost of production overhead investment on gas leases and dividing by successful well costs. These relationships were most recently determined from data filed in response to the AR69-1 Questionnaire.

Staff and UDC utilize a ratio of 0.226 derived from the AR69-1 Questionnaire data, and the Producers use a ratio of 0.2675 taken from Exhibit No. 63 in the same proceeding. The difference between the cost of this component as determined by Staff and UDC and as determined by the Producers is approximately 0.24 cents per Mcf.

The Commission adopts the ratio used by Staff and UDC. Applying this ratio of 0.226 to a successful well cost range of 4.99 cents per Mcf to 5.68 cents per Mcf, the other production facilities cost component is found to range from 1.13 to 1.28 cents per Mcf.

(5) *Dry Hole Costs*

Dry hole costs are calculated by dividing the cost per foot of dry hole drilling for a given year by the productivity of successful wells (Mcf per foot) to arrive at a cost for dry holes in terms of cents per Mcf.

Dry hole costs for 1972 as reported by JAS were \$16.94 per foot (excluding Alaska). The dry hole cost

[2713]

determined by dividing the cost per foot of dry hole drilling by the selected productivity is then adjusted upward to reflect the greater depth and thus higher costs and the offset of higher success ratio at those depths for gas well drilling as compared to oil well drilling. *See, Area Rate Proceeding, et al. (Permian Basin),* 34 F.P.C. 159, 291-292 (1965). These depth factors were derived from published American Petroleum Institute data on drilling footage by depth range and type of drilling, JAS drilling cost per foot for dry holes, and data from *World Oil* concerning the relationship of total gas and condensate footage to the total successful footage.

The net combined adjustment factor was taken by Staff and UDC to be 1.08. The Producers calculated the ratio

as 1.12 based upon data for the most recent four year period. In view of the short span of time used by IPR to calculate this component, the Commission has concluded that the ratio of 1.08 as used by Staff and UDC should be adopted in this decision. The difference in dry hole costs due to the use of a ratio of 1.12 instead of 1.08 is only 0.14 cents per Mcf.

Dry hole costs are found to range from 3.32 to 3.77 cents per Mcf based upon an adjustment factor of 1.08, 1972 JAS dry hole costs, and productivities of 485 and 552 Mcf per foot.

(6) *Other Exploration Costs*

Other exploration costs were calculated differently by the parties.

Staff and UDC calculated this cost component by multiplying the lease acquisition cost component by the ratio of national other exploration costs divided by lease acquisition costs. Staff and UDC and JAS data for 1967 to 1971 to determine a ratio of 0.7686.

The Producers calculated this component by multiplying the successful well cost component by the ratio of national other exploration costs divided by successful well costs. IPR used a five year moving average of JAS data to calculate a ratio of 0.449.

[2714]

Updating the ratio used by Staff and UDC to calculate this cost component to account for 1972 JAS data results in a ratio of 0.6844. Applying this ratio to the lease acquisition cost component range of 3.36 to 3.83 cents per Mcf yields an other exploration cost component range

of 2.30 to 2.62 cents per Mcf. The Producers' determination of this component is approximately 0.24 cents per Mcf less than the allowance calculated using the updated ratio adopted by Staff and UDC.

The Commission finds that a range of 2.30 to 2.62 cents per Mcf for the other exploration cost component is reasonable.

(7) *Exploration Overhead*

Staff calculated this component by multiplying the sum of the dry hole and other exploration costs by the ratio of national exploratory overhead costs divided by the sum of national and other exploratory costs using the average of JAS data for 1967 to 1971.

Updating the methodology used by Staff and UDC to calculate this component to account for 1972 JAS data yields a range of 0.72 to 0.82 cents per Mcf. Application of the methodology used by the Producers would yield an allowance of 0.75 cents per Mcf for this component.

The Commission finds that an allowance of 0.72 to 0.82 cents per Mcf is appropriate to cover the cost of exploration overhead.

(8) *Production Operating Expense*

Staff adopted 3.10 cents per Mcf as its production operating expense based upon the Southern Louisiana Area Rate Proceeding,[107] and this figure was accepted by IPR. UDC started with this same figure, but adjusted it for inflation at five percent per year to arrive at a 1973 production operating expense of 3.77 cents per Mcf.

107. 46 F.P.C. 86, 133 (1971).

[2714]

The production operating expense is calculated by dividing the operating expenses for gas leases by the production from gas leases. The production volumes are converted from gross wet volumes to net dry volumes and from working interest volumes to one hundred percent

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interest volumes to compensate for the fact that other cost elements are derived in relation to the AGA gas reserve volumes rather than the production volumes. The most recent computation of production operating expenses was based on data collected in the AR69-1 Questionnaire.

The only difference between Staff, the Producers and UDC on the calculation of this component was UDC's escalation for inflation. We have previously stated our reluctance to escalate drilling costs for inflation and we do not believe that an inflation factor should be applied to adjust the operating expense allowance. The data being collected and composited in Docket No. R-478 will provide a more appropriate basis for adjusting this component in a future proceeding than will an arbitrary inflation rate in this proceeding.

Production operating expense of 3.10 cents per Mcf is found to be reasonable.

(9) *Return on Production Investment*

Based upon a fifteen percent rate of return and an investment life range of 9 to 10.5 years as previously determined, the return component is found to range from 15.09 to 17.15 cents per Mcf.

The return on production investment is calculated by multiplying the production investment (9.58 to 10.89

cents per Mcf—total production investment less one-half of the 0.20 cents per Mcf allowance for recompletions and deeper drilling) by the investment life and then multiplying that product by the 15 percent rate of return. One-half of the allowance for recompletions and deeper drilling is deducted from the rate base on the assumption that these expenditures are incurred at the midpoint of the average depletion period.

A range of 15.09 to 17.15 cents per Mcf for the return on production investment component is found to be reasonable.[108]

[2716]

The adoption of full cost accounting would add approximately 11.66 cents per Mcf to 13.31 cents per Mcf to the low and high ends of the reasonable cost range.[109] As we have previously indicated, the adoption of the principles of full cost accounting in this proceeding is not warranted nor justified by the record.

Similarly, AGD's recommendation for a return on dry hole cost equal to one-half the rate of return times the dry hole costs would add 5.73 cents per Mcf to 6.55 cents per Mcf to the low and high ends of the cost range.[110]

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108. If a 12 percent rate of return had been utilized in lieu of the 15 percent, the return component would range from 12.07 cents per Mcf to 13.72 cents per Mcf and the total rate would range from 33.94 cents per Mcf to 38.65 cents per Mcf.

109. Adjustment for 1.7 Tcf disparity would result in the addition of 11.57 cents per Mcf to 13.05 cents per Mcf to low and high ends of this cost range.

110. Adjustment for the 1.7 Tcf disparity would add 5.66 cents per Mcf to the low end and 6.42 cents per Mcf to the high end of the range.

The adjustment of average nationwide costs to reflect the principles of full cost accounting, not necessarily utilized by any company, does not coincide with common sense nor regulation in the public interest. The rates yielded by the utilization of full cost accounting in our costing methodology are found to be excessive and outside the reasonable and permissible cost range of 37.54 to 42.74 cents per Mcf. Thus, we find it necessary to reject the utilization of the principles of full cost accounting as a means of computing the return on investment component.

[2717]

The Major Producers Group urged the Commission to undertake "a complete reappraisal . . . of its costing methodology and rate of return application,"[111] based upon alleged "basic and fatal deficiencies" in the new gas costing methodology first adopted by the Commission in *Permian I* and most recently affirmed on June 14, 1974, by a unanimous Supreme Court of the United States in *Mobil Oil Corp. v. FPC, supra.* The Producers claim that the methodology has three "built in biases": (1) a return allowance only on a portion of investment outlays; (2) use of past costs and not future expected costs; and (3) failure to recognize the "basic mathematics of yield and rate of return."[112] The first of these points is discussed in the analysis of the rate base and full cost accounting.[113] The second is discussed in the "Cost Factors" section.[114]

111. Joint Comments of Indicated Producer Respondents, May 7, 1974, pp. 3-4.

112. *Id.*, p. 4.

113. See pp. 64-70.

114. See pp. 43-45.

In this section we examine the third of the alleged methodological "biases" as set forth in Dr. Ezra Solomon's presentation.[115]

We do not take issue with Dr. Solomon's demonstration that, given certain standard assumptions, the "true yield" in a discounted cash flow (DCF) costing format will be less than the specified rate of return in the rate-base costing format employed by the Staff. As he states, it is a matter of "basic mathematics." The matters on which we disagree are his presumption that the DCF format is ripe for adoption in this proceeding and his claim that the DCF methodology will

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provide a more realistic and more accurate cost estimate than is obtainable with the alternative methodology we have adopted. We are bound by the record that is before us, which lacks the necessary information for a reliable DCF cost estimate, and we are convinced that, in view of these informational gaps, the inherent uncertainties of cost estimation cannot be eliminated or even reduced by substituting a DCF costing format for the rate base costing methodology. We fully appreciate the conceptual niceties of DCF costing. The translation of concepts into practical applications is the troublesome part although, as explained below, we have experimented with various DCF models for possible use as checks on the results of our own methodology.

The problems with the DCF approach are illustrated in the Statement of Robert H. Park.[116] Mr. Park has

115. Major Producer Response, May 7, 1974, Appendix A.

116. See Supplemental Reply Comments of Texaco Inc., May 28, 1974.

presented four alternative DCF calculations all designed to support a 75 cent price (including production tax) with "true yield" equating to rates of return of 15 percent to 18.4 percent. We have recalculated Mr. Park's DCF model using a 15 percent "true yield" and all of his cost parameters except for the substitution of productivity of 485 Mcf/foot, which is the productivity assumption for our high cost estimate. On that basis the calculated DCF price is reduced from 75 cents to about 57 cents (excluding production tax).[117] We have also experimented with other reasonable modifications of Mr. Park's DCF model, such as compressing the time of pre-production investment, accelerating the production rates in the early years, and

[2719]

allowing a capital contribution from flowing gas reserves.[118] These changes reduce the estimated price that is supported by the analysis to about 41 cents (excluding production tax) compared with a price of 42 cents (excluding production tax) plus 1 cent annual escalations (or an equivalent present value price of 47 to 48 cents)[119] which we have found to be the just and reasonable price for new gas.

These experimental adjustments of the DCF model do not exhaust the range of reasonable modifications to

117. See Appendix H, Case I.

118. *Id.*, Case II. For illustrative purposes, a capital contribution from flowing gas revenues of 3¢ per Mcf was used. In our most recent area rate cases, an additional allowance above costs for increased exploration and development was allowed. Such allowances were adopted in *Permian II* case—3.5¢ per Mcf (Opinion No. 662, *mimeo.* pp. 1, 5). *See also, Southern Louisiana II*, 46 F.P.C. 86, 135-138 (1971); and *Texas Gulf Coast*, 45 F.P.C. 674, 707-709 (1971); *Area Rates For The Rocky Mountain Area*, 49 F.P.C. 924, 944 (1973).

119. See pp. 110-112.

Mr. Park's illustrative calculations. We have an even more basic reservation regarding the model's use in the context of this proceeding. DCF has proven to be a practical tool for individual project evaluations by companies faced with decisions on where to invest their money and how much to invest. The appropriateness of using the DCF format to estimate the national average cost of new gas raises an entirely different question. The typical gas producer has projects in various stages of development or production. His financing of new projects usually is derived from flowing gas revenues as well as from external sources. The DCF presentations of Dr. Solomon and Mr. Park completely ignore the interrelationship between flowing gas revenues and new gas costs. Clearly, this Commission cannot set a price for new gas without also considering the cash flow consequences of its pricing policies for old gas.

[2720]

This problem is clearly identified in *Southern Louisiana II* where we stated: "So the significant argument is whether flowing gas realizations should bear a part of the responsibility for assuring a cash flow to meet the needs for a heightened exploration and production effort. *We believe they should.*"[120] At a later point, the Commission endorsed the Staff's flowing gas costs and explained: "By recommending a flowing gas price higher than that arrived at in Opinion No. 546 . . . and then further recommending acceptance of the settlement at a still higher level . . . Staff was candidly and correctly making the flowing gas cost bear a part of the responsibility for further exploration—in other words, it was looking at the total rate

120. 46 FPC 136 (Emphasis added).

design."[121] The Commission's insistence on viewing the new and old gas ceiling rates as parts of an overall regulatory plan was given explicit approval by the Supreme Court in its recent decision in *Mobil Oil Corp. v. F.P.C.*, as follows: "Thus, the ceiling rate for flowing gas established by the Commission includes a noncost factor designed to facilitate investment by producers in exploration and development of new gas reserves."[122] In discussing "the permissible range of the Commission's authority to employ price to encourage exploration or production" the Court went on to say: "As between placing the burden of that expansion on new or second vintage gas alone or spreading it over both old and new gas, [the Commission] judged the latter more equitable and more likely to lead to the immediately increased capital necessary in the face of a crisis."[123]

[2721]

To the extent that the capital for new gas projects is derived from noncost allowances included in the ceiling rates for flowing gas, it is consumer contributed capital that is available for reinvestment in new gas ventures. A producer is entitled to a fair return on his own capital but not on his use of consumer contributed capital. The DCF models presented by Mr. Park assume that the entire capital outlay is necessarily financed out of borrowed funds or investor contributed capital.

121. 46 FPC 137. A similar line of reasoning appears in other area rate opinions. *Area Rate Proceeding, et al. (Texas Gulf Coast Area)*, 45 F.P.C. 674 (1971) (*mimeo.* pp. 38-39); *Area Rate Proceeding, et al. (Other Southwest Area)*, 46 F.P.C. 900 at 916-919 (1971); *Area Rate Proceeding (Permian Basin Area II)*, Opinion No. 662, ____F.P.C.____ (August 7, 1973) (*mimeo.* pp. 1, 5).

122. Slip opinion, p. 5, footnote 5.

123. Slip opinion, pp. 32, 33.

We, of course, recognize that our various concerns over the practicality of adopting a DCF costing format in this proceeding do not reach the "basic mathematics" of DCF versus the rate base methodology adopted herein. According to our calculations, the new gas price of 42 cents per Mcf plus 1.0 cent annual escalations, as provided herein, will produce a "true yield" of at least 12.6 percent (rather than the 15 percent return allowed on rate base) which is within the zone of reasonable rates of return found herein.[124] We do not view this calculation as evidence that the 15 percent allowance is in any way inadequate in the context of our methodology. We would note, first, that our new gas costing is only for non-associated (or gas-well) gas, but that the rate is also applied to casinghead (or oil-well) gas, so that the producer is allowed more than 15 percent return on his casinghead gas production under our methodology.[125] Secondly, under the provisions of this decision, old gas

[2722]

also lower cost gas, can command the new gas price at the end of its contract term, as can other gas from wells commenced in earlier years and now being dedicated for the first time to interstate commerce. Finally, it should

124. See Appendix H, Case III. The above calculation is based upon a constant rate of production over an 18-year life and a time lag of 1.5 years for pre-production investment. The calculated "true yield" is higher than 12.6 percent if we allow for such assumptions as accelerated rates of take and a capital contribution from flowing gas revenues. As noted above (pp. 86-7) under certain plausible assumptions, the 42 cents per Mcf base price can be reconciled with a 15 percent "true yield."

125. "Casinghead gas has traditionally been treated as a byproduct of oil and therefore costed and priced lower than gas-well gas." *Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (Slip opinion at p. 41).

be recognized that the allowed rate of return is a *lifetime average* rate of return based on today's exceptionally high cost of capital due to inflationary conditions. While we do not claim any competence in forecasting how soon these abnormal conditions will subside, we cannot overlook the fact that the returns of 10 to 12 percent that are available in today's capital markets do not carry a comparable lifetime assurance.

For all these reasons, we believe that for the Commission to depart from the costing methodology it has used in all previous producer rate cases would be irresponsible at this final rulemaking stage. While our own costing methodology does not incorporate the "true yield" return of a DCF costing, that fact in itself does not indicate that our range of cost estimates is not supported by substantial evidence. The rates prescribed herein will accomplish the end result of attracting the capital to produce a return competitive with the return on other investments of corresponding risks when tested by the revenue reasonably to be anticipated from internal and external sources of financing over the life of the investment. *FPC v. Hope Natural Gas Company,* 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 597 (1923).

There are some features of our own methodology which probably overstate the cost (i.e., failure to allow for accelerated takes in early years) and other features which may understate the cost (i.e., the use of a mid-point rate base). On balance, however, we find that the methodology produces a reasonable end result and that our experimentation with DCF models tends to confirm this conclusion.

[2723]

(10) *Return on Working Capital*

All parties utilized the methodology adopted in Opinion No. 598[126] to calculate the return on working capital. A fifteen percent rate of return was utilized by all parties except that UDC also utilized a 16 percent rate of return for its high cost estimate.

The computation of the return on working capital is derived from the traditional utility working capital formulas which are based upon a 45 day collection period. (The one-eighth factor is derived from the ratio of 45 days to 360 days.) *Area Rate Proceeding, et al. (Permian Basin),* 34 F.P.C. 159, 204 (1965). This method allows a return on the sum of materials and supplies, and prepayments plus one-eighth of production and exploration operating expenses. In addition, an allowance for "lease play" was adopted in the first Permian Opinion. 34 F.P.C. 159 at 205-206. This allowance was taken to be 1.5 times the lease acquisition costs. This method and the basic factors (discussed below) were adopted by all parties presenting cost studies in this proceeding.

The factor of 1.336 expresses the relationship between one-eighth of the exploration and development operating expenses, material and supplies, and prepayments. The 1.336 factor was derived by employing cost data on these elements in the responses to the AR69-1 Questionnaire.

The factor of 1.689 expresses the relationship between one-eighth of the producing operating expenses, material and supplies, and prepayments. Again this factor was derived from AR69-1 Questionnaire data.

126. 46 F.P.C. 86 (1971).

[2723]

Using these factors in the traditional working capital equation to compute a return on working capital yields a range of 1.01 to 1.14 cents per Mcf.

(11) *Net Liquid Credit*

The net liquid credit reflects an estimate of the revenues that the producer will receive from processing non-associated gas to remove hydrocarbon components having a molecular weight greater than the molecular weight of methane.

Staff adopted a net liquid credit of 3.89 cents per Mcf based upon data from the AGA Reserve Reports for

[2724]

1965 through 1969, Bureau of Mines data on processing plant liquids for the years 1965 through 1969, and data reported in the responses to the AR69-1 Questionnaire. UDC and the Producers both adopted this figure, but the Producers contended that a cost allocation method based upon vapor volume equivalent should be used instead of the methodology adopted by the Staff. The Producers, however, did not calculate a net liquid credit using its vapor volume methodology.

While a net liquid credit of 3.89 cents per Mcf has been utilized in this decision, the Commission is of the opinion that the recent increases in the prices paid for condensate cause this component of the cost analysis to be understated. The recent price increase for crude petroleum allowed by the Cost of Living Council will also result in an increased price paid for condensate, and this will cause the net liquid credit to be further understated. The Commission has not increased the amount of the net liquid credit since there is some evidence that the

amount of condensate produced from gas-wells is declining and partially offsetting the increases in the prices paid for condensate. The Commission is aware of these changes which are affecting the proper allowance for the net liquid credit and is evaluating the effect of these changes on the cost of new natural gas supplies.

The Commission concludes that 3.89 cents per Mcf is a reasonable allowance for the net liquid credit.

(12) *Regulatory Expenses*

All parties submitting cost studies adopted 0.20 cents per Mcf which was stipulated to in the second Permian Basin proceeding as an adequate allowance for regulatory expenses.[127]

The Commission concludes that 0.20 cents per Mcf should be adopted as an allowance for regulatory expenses

[2725]

(13) *Royalty*

Royalty expenses represent the percentage of the gross receipts the producer must pay over to the land owner for the privilege of extracting the gas from reserves underlying that land.

All parties used an average royalty of sixteen percent in their cost calculations. Previous opinions of this Commission have utilized an average royalty of fifteen percent, but the Federal offshore leases carry a royalty of 16-2/3 percent and the fact that the offshore leases represent an increasing share of the total leases requires that

127. *Area Rate Proceeding (Permian Basin Area)*, Docket No. AR70-1 *(Phase I), Initial Decision, mimeo.* p. 46.

consideration be given to increased royalty expenses, and 16 percent will be adopted as the basis for calculating royalty expenses.

The Commission finds that the foregoing yields a range of royalty values of 6.01 to 6.84 cents per Mcf, and further finds a royalty component range of 6.01 to 6.84 cents per Mcf to be reasonable.

F. *Gathering Allowance*

A number of parties to this proceeding have commented that the proposed downward adjustment of the national rate of 0.5 cents per Mcf for deliveries made closer to the wellhead than a central point in the field, the tailgate of a processing plant, an offshore platform, or a point on the buyer's line would work a hardship on producers who perform gathering activities in producing areas where it is common for producers to gather the natural gas. The allowance or disallowance of a gathering allowance in past area rate cases has depended upon where the majority of the gas produced in individual areas

[2726]

is delivered to the buyer.[128]

This practice should be followed on a national basis, and this decision shall provide for a gathering allowance.

128. Thus a gathering allowance was provided in the Hugoton-Anadarko Area, 44 F.P.C. 761, and in the second Permian Basin proceeding, Opinion, No. 662 (August 7, 1973), but deductions for deliveries closer to the wellhead than a central point in the field, the tailgate of a processing plant, an offshore platform, or a point on the buyer's line were provided in Southern Louisiana Area, 46 F.P.C. 86, Texas Gulf Coast Area, 45 F.P.C. 900. A gathering allowance was made part of the base area rate in the Appalachian and Illinois Basin Areas, Order No. 411, 44 F.P.C. 1112, 1123. It was recognized that most sales were made at the wellhead in the Rocky Mountain Area, Opinion No. 658, 49 F.P.C. 924, 937 (1973).

A gathering allowance of 2.5 cents per Mcf will be allowed for natural gas produced from the "Panhandle and Hugoton Fields" of the Hugoton-Anadarko Area, and an allowance of 1.0 cents per Mcf will be included for natural gas produced in the "other fields" of the Hugoton-Anadarko Area, the Permian Basin Area, and the Rocky Mountain Area for deliveries at the tailgate of a processing plant, or at a point on the buyer's pipeline beyond the wellhead and beyond the central point in the field.

Producers who do not recover the cost of their gathering activities as a result of the above allowances can petition this Commission for special relief as hereinafter provided. The above gathering allowances have been found to be just and reasonable and are adopted as part of the rate structure established herein.

[2727]

g. *Summary of Costs*

The foregoing cost components, and the deduction for the liquid credit, when taken together, result in a range of 37.54 to 42.74 cents per Mcf at 14.73 psia, exclusive of any state or federal production, severance, or similar taxes, for the cost of new nonassociated natural gas supplies on a nationwide basis.[129] We find 37.54¢ per Mcf to 42.74¢ per Mcf a reasonable cost range (Schedule 1, Columns (f) and (g), Appendix C) based upon all the evidence in this proceeding including the most reasonable presentations of each of the cost components that were submitted by the parties herein, and upon data and in-

129. Appendix C (Schedule No. 1, Columns (f) and (g), Sheet 1 of 9). The effect of state taxes and other adjustments on the base national rate is shown in Appendix D.

formation made available from comments and submittals contained in the record of this proceeding.

The gathering allowance adequately provides for the recoupment of costs incurred in extensive gathering operations and follows the practices adopted by the various area rate opinions in the treatment of gathering allowances.

h. *Summary of Costs Based Upon Adjusted Productivity Factors*

In addition to the foregoing cost analyses, we have also computed a range of costs based upon AGA reserve additions adjusted to reflect a disparity of 1.7 Tcf as reported in our notice of March 21, 1974. These cost computations yield a reasonably reliable cost range of 37.01 cents per Mcf to 41.9 cents per Mcf based upon the 1.7 Tcf disparity.[130]

[2728]

Combining these "adjusted" results with the unadjusted cost range which has previously been discussed in detail yields a total "zone of reasonableness"[131] ranging from a low of 37.01 cents per Mcf based upon a ten year (1963-1972) productivity factor to 42.7 cents per Mcf. It is from this total "zone of reasonableness" that we make our

130. The low estimate (37.01 cents per Mcf) is based upon a productivity of 559 Mcf per foot drilled which is the average for the most recent ten year period ending with 1972 adjusted by increasing 1971 and 1972 reported reserve additions by a total of 1.7 Tcf. The high estimate (41.9 cents per Mcf) is based upon a seven year period ending in 1972 with the previous 1.7 Tcf adjustment. The low estimate and the high estimate are based upon 10.5 year investment life. *See* Revised Appendix C (Schedule No. 1, Columns (a) and (e), Sheet 1 of 7).

131. *FPC v. Natural Gas Pipeline Co.,* 315 U.S. 575, 585 (1942).

rate determinations. On the high side of the zone even the adjusted cost calculation yields a result of 41.9 cents per Mcf (Schedule 1, Column (d), Revised Appendix C, Sheet 1). Therefore, we conclude that a base rate of 42.0 cents per Mcf is justified on the basis of costs alone and proceed to identify other elements of the total rate structure.

2. *OTHER CONTRACT TERMS*

After careful review and consideration of all the comments filed in this proceeding, we conclude that the base national rate herein established should be made applicable to sales made pursuant to contracts executed on or after January 1, 1973, for the sale of natural gas in interstate commerce where such gas has not been previously sold in interstate commerce except pursant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Order No. 491, *et seq., supra* n.4); and sales made pursuant to contracts executed on or after January 1, 1973, where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after January 1, 1973, in accordance with Opinion No. 639,[132] as well as jurisdictional sales of natural gas made from wells commenced on or after January 1, 1973. (All three classes of sales are hereinafter referred to as R-389-B Dedications). This clarification of the scope of our rulemaking is consistent with past Commission practices of pricing new dedications of natural gas to interstate commerce by

132. *Area Rates For The Appalachian And Illinois Basin Areas,* Docket No. R-371, 48 F.P.C. 1299 at 1309-1310 (1972), *affirmed sub nom. Shell Oil Co., et al. v. FPC,* 491 F.2d 82 (5th Cir. 1974).

[2728]

the contract date (E.g., *Southern Louisiana*, 46 F.P.C. 86, 142-143) and the

[2729]

eliminating of vintaging as contracts expire by their own terms (*see* n. 132, *supra*). Moreover, this clear statement of the scope of the proceeding will insure that the additional revenues generated by the two classes of sales will be available for the expanded exploration and development programs which are required to discover and produce the new supplies of natural gas that will be needed to help fulfill anticipated future demands. Moreover, clarification of the scope of this proceeding to include expiring contracts and former emergency sales will offset the claimed attrition in rate of return in various discounted cash flow studies presented by producer respondents. The implicit rate computed in Exhibit RHP-1 (Witness Parks), does not reflect the substantial additional cash flow from these sales which on a discounted basis would contribute to increased realized return.

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One of the primary purposes in instituting this rulemaking proceeding was to encourage new dedications of natural gas to the interstate market "whether such new supplies come from new acreage dedications, or from newly drilled wells, or by diversion from other uses." Order No. 455, *supra*, 48 F.P.C. 218, 227. The most appropriate means of eliciting the new dedications of natural gas required to meet the existing and future reasonable demands of the interstate markets is to make those markets attractive to producers who have supplies of natural gas to sell. At the same time, we desire to limit the applicability of the rate established herein to those sup-

plies which first became available to the interstate market near in time to the issuance of the notice instituting this proceeding. 38 *Fed. Reg.* 10014 (April 11, 1973), or which because of an expiring contract are again subject to contractual negotiation. We have, therefore, determined that the rate established by this decision will be available only to those classes of jurisdictional sales which we refer to as R-389-B dedications. This follows our well established practice of providing a dividing date near in time to the commencement of the proceeding. See *Permian Basin Area Rate Proceeding, et al.*, 34 F.P.C. 159, 188-189 (1965), *affirmed, Permian Basin Area Rate Cases*, 390 U.S. 747 (1968). Such a division will provide the incentive necessary to encourage expanded exploration and development programs and new dedications of natural gas to the interstate market. As to the use of the contract date to establish eligibility for the national rate prescribed by this decision, we believe that the use of the contract date to determine the applicable rate for natural gas sold in interstate commerce should be modified. Where a new long-term gas sales contract is executed on or after January 1, 1973, for sales which have not previously been sold in interstate commerce other than under our emergency sales procedures or where a new contract is executed with respect to an existing interstate sales where the previous

[2731]

sales contract has expired by its own terms and the provisions of Commission Opinion No. 639 (*supra*, n. 132), such gas will be eligible for the R-389-B rate.

We have also determined that natural gas producers who elect to discharge their existing refund obligations

under prior area rate opinions by dedicating new supplies of natural gas to the interstate market from wells commenced on or after January 1, 1973, will be required to price such natural gas at the rate established by the applicable area rate opinion.[133] The same condition shall apply to those producers who desire to obtain the contingent escalations for flowing gas as provided in Opinion Nos. 595, 598, 607, and 662, and they shall also be required to dedicate those new natural gas supplies which they seek to have applied toward triggering the flowing gas escalations at the rates provided in those opinions. This treatment is equitable since the rates established in those opinions were determined to be sufficient to encourage exploration and development activities when coupled with the refund credit incentives and contingent escalations provided in those opinions. To allow producers to collect the rate provided by this decision and to discharge their existing obligations and receive the benefits provided under the applicable area rate opinions with the same supplies of natural gas would be contrary to the spirit of the applicable area rate opinions. In essence, we seek to insure that a producer will not receive a double benefit from the rate structure which we establish in this decision.[134]

133. *Southern Louisiana Area Rate Proceeding,* Docket No. AR69-1, *et al.,* Opinion No. 598, 46 F.P.C. 86, 141, 147-148 (1971); *Texas Gulf Coast Area Rate Proceeding,* Docket No. AR64-2, *et al.,* Opinion No. 595, 45 F.P.C. 674, 709-710, 721 (1971); *Other Southwest Area Rate Proceeding,* Docket Nos. AR67-1, *et al.,* Opinion No. 607-A, 47 F.P.C. 99, 100, 102 (1972); *Area Rate Proceeding (Permian Basin Area II),* Docket No. AR70-1 (Phase I), Opinion No. 688, ____ F.P.C.____ (August 7, 1973).

134. *See Stingray Pipeline Company, et al.,* Docket No. CP73-27, *et al.,* Opinion No. 639, p.____F.P.C.____ (May 6, 1974), *reh. denied,* Opinion No. 693-A, ____F.P.C.____ (June 13, 1974).

[2732]

Where a producer has commenced a sale of natural gas in interstate commerce from wells commenced on or after January 1, 1973, and the volumes of gas from that sale are being credited toward the producer's refund obligation or applied to triggering the contingent escalations in the aforementioned area rate opinions (*See* n. 133, *supra.*), the producer will not be allowed to both receive the price prescribed herein and continue to receive the refund credit or contingent escalation credit. The producer must make a decision as to whether it is more beneficial to receive the higher rate prescribed by this opinion and waive the refund credits and contingent escalations or to sell the gas at the applicable area rate and retain the refund credits and contingent escalations.

To insure that producers do not gain a double benefit under this opinion we shall require a written waiver of the contingent escalations and refund credits with respect to gas which is dedicated under the provisions of the decision. That waiver shall state whether such gas has previously been sold in interstate commerce in discharge of refund obligations or toward the triggering of contingent escalations, the date the subject wells were commenced, whether the gas was previously sold in interstate commerce under 18 C.F.R. §§2.68, 2.70, 154.22 or 154.29, or whether the gas comes within the provisions of Opinion No. 639, and shall affirmatively waive the right to either refund credits or contingent escalations for the gas.

[2733]

After review of the comments filed in this proceeding, it is concluded that those proposed provisions which would

have required upward Btu adjustments be made from 1050 Btu per cubic foot and downward Btu adjustments be made from 1000 Btu per cubic foot should be modified to provide the both upward and downward Btu adjustments will be made from a base of 1000 Btu per cubic foot. This modification will simplify the rate structure established herein and, to the extent that methane and other compounds are not removed from the gas during processing, the consumer will benefit from the additional Btu content.

All quality provisions other than the Btu adjustment established herein are to be determined by the contract between the buyer and the seller.

After careful consideration of the comments addressed to the proposed annual review of the uniform national rate established by this order, we are convinced that our proposed review should be conducted on a biennial basis rather than on an annual basis. In this time of continuing inflation and the increasing costs of finding and producing new supplies of natural gas to meet the nation's demands for energy, we must provide a mechanism whereby these increased costs can be recouped by the producer. This recoupment can be accomplished by providing fixed periodic escalations which are based upon some type of index or set figures, or by providing a biennial review of the previously established rates, or by providing both as we do in this Opinion. We believe that the biennial review allows greater flexibility and a more comprehensive review of the impact of the then effective rates upon the producing industry, the demand for and supply of natural gas with a more comprehensive data base than an annual review would allow. Our purpose in

adopting a single uniform national rate is to elicit sufficient supplies of natural gas to meet the demands in the consumer market at a price no higher than the price necessary to elicit that supply. A biennial review of the established rate makes it possible to determine if that rate was sufficient to bring forth the supply of gas to fulfill the demand.

[2734]

The biennial review will be concerned with the current cost of finding and producing new gas sales and will apply prospectively to wells commenced on or after the date prescribed by the Commission order instituting a new proceeding to conduct the biennial review. Thereafter, a similar review will be conducted every two years. This rate will constitute a new just and reasonable rate for gas supplies from those wells only and will not be applicable to wells drilled prior to the date specified by the order instituting the new proceeding. This review will be conducted in the same manner as this proceeding unless otherwise ordered by the Commission.

We find that a biennial review will enable the Commission to prescribe just and reasonable rates by application of the most recent evidence supporting those rates. The first biennial review will be initiated to establish rates for natural gas produced from wells commenced on or after January 1, 1975, or natural gas sold pursuant to contracts executed on or after that date for gas not previously sold in interstate commerce except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, or 157.22, and to sales of natural gas formerly made in interstate commerce pursuant to gas sales contracts which expired on or after January 1, 1975. Thereafter, a biennal review

will be conducted to prescribe rates for each succeeding biennium.

[2735]

Where a producer at his sole cost transports natural gas produced in an offshore area onshore before delivery to the purchaser, the producer shall be entitled to collect an additional 1.0 cent per Mcf in addition to the uniform national rate. This treatment follows the practice adopted in the area rate cases and should be continued.[135]

The single uniform national rate which is prescribed by this decision shall be applicable to all types of natural gas (casinghead, gas well, or residue) produced from wells commenced on or after January 1, 1973, to contracts executed on or after January 1, 1973, covering the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Order No. 491, *supra,* note 4), and to contracts for the sales of natural gas in interstate where the prior contracts for the sale of such gas in interstate commerce expired by its own terms on or after January 1, 1973. This rate is applicable only to jurisdictional sales of natural gas within the continental United States excluding Alaska and Hawaii. The national rate is subject to adjustment for Btu content, state and Federal production taxes, and the annual escalation provided herein, and the applicable gathering allowance.[136]

135. Southern Louisiana, 18 C.F.R. §154.105(h).

136. See Appendix D for calculation of effective date including adjustments.

[2736]

Finally, the existing moratoria on price increases above the ceiling rate established in the Appalachian Illinois Basin,[137] Hugoton-Anadarko,[138] Other Southwest,[139] Southern Louisiana,[140] and Texas Gulf Coast[141] areas should be modified to permit producers to collect the rates prescribed herein for natural gas sold in interstate commerce where such gas falls within one of the three classes of gas sales to which this decision is applicable (*See* p. 96, *supra*). To retain these moratoria would place producers in these areas at an unfair disadvantage with respect to producers operating in producing areas not subject to moratoria on price increases,[142] and would discourage the increased level of exploration and development which the new national rate should elicit.

As we have previously mentioned (pp. 99-100), the producers seeking to collect the rate established herein will be required to waive their right to have such gas discharge their refund obligations or trigger the contingent escalations provided by Opinions 595, 598, 607, and 662 for gas which comes within the scope of this proceeding (p. 96 *supra*) if that gas is currently being used to discharge refund obligations or trigger contingent escalations. Thus, we are providing for a selective, rather than an across-the-board, lifting of the existing moratoria on price increases in the specified areas.

137. 18 C.F.R. §§154.107, 154.108.

138. 18 C.F.R. §154.160.

139. 18 C.F.R. §154.109a.

140. 18 C.F.R. §154.105.

141. 18 C.F.R. §154.109.

142. There is no moratorium in the Permian Basin Area. See Opinion No. 662, *mimeo.* p. 14.

[2737]

As we have previously stated, the refund credits and contingent escalations are an integral part of Opinions 595, 598, 607, and 662, and the rate structures promulgated in those opinions. It is not possible to separate these benefits from the rates established in those area rate opinions since the refund credits and contingent escalations are inextricably entwined with the monetary rates established in those opinions and the two may not be separated without damage to the whole.[143] Thus, we conclude that producers selling gas in interstate commerce which would be eligible for the rate established by this decision except for the fact that such gas is presently being utilized to discharge either refund obligations or to trigger the contingent escalations will be allowed to receive the price established herein if the producer waives his right to apply the volumes of the gas toward discharge of the refund obligation or triggering of the contingent escalations prospectively as of the date of this opinion.

B. *SPECIAL RELIEF*

Our previous area rate opinions made provisions for special relief in unusual circumstances where the area rate was not sufficient to recover the cost of producing natural gas already dedicated to the interstate market. In many cases, the circumstances which would support the granting of special relief are also sufficient to permit abandonment of the sale. *Permian I*, 34 F.P.C. 159, 226 (1965).

143. The Supreme Court recently held that it is within the Commission's discretion to make such benefits a part of its rate structure. *Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (slip opinion 34-39).

Without attempting to enumerate all circumstances which would form an adequate basis for granting special relief, we shall grant special relief where the producer can demonstrate that the out-of-pocket expenses incurred in the operation of a particular well (or group of wells) are greater than revenues from the sale of the subject gas. *See, Permian Basin Area Rate Cases,* 390 U.S. 747, 770-773. It is incumbent upon the producer seeking special relief to prove by his books and accounts that the operating expenses are in excess of the revenues earned from the sale of the gas from such well or wells.

[2738]

There are also other avenues of extraordinary relief for a producer who may be adversely affected by the rate established in this proceeding. Where a producer has already dedicated gas to the interstate market and a change in circumstances makes continued production uneconomical, the producer may seek relief under Order No. 481[144] or Order No. 482.[145] Where the producer has not already committed the subject acreage of gas supply to the interstate market, he may seek certification of the sale under Order No. 455. *See* n. 5, *supra.*

In those cases where a producer seeks special relief because of Federal income taxes payable as a result of his natural gas production we shall require that he submit

144. 18 C.F.R. §2.76; *Policy With Respect To Sales Where Reduced Pressures, Need For Reconditioning, Deeper Drilling, Or Other Factors Make Further Production Uneconomical At Existing Prices,* Docket No. R-458, 49 F.P.C. 992 (1973), as amended by *Order Amending Order No. 481 And Granting And Denying Petitions For Rehearing,* 49 F.P.C.____ (June 8, 1973).

145. 18 C.F.R. §2.77; *Flaring And Venting Of Natural Gas,* Docket No. R-459, Order No. 482, 49 F.P.C. 996 (1973).

certified copies of his Federal income tax returns and the supporting schedules as a part of the petition. Any petition for special relief on account of Federal income taxes payable that is not accompanied by the verified tax returns and supporting schedules will be rejected without consideration by the Commission.[146]

Special provisions for deeper drilling and deeper water depths are provided *infra* pp. 129-133.

[2739]

As this Commission noted in the first Southern Louisiana proceeding, there are circumstances which may make certain production more attractive to purchasers but which are not related to the costs of production, and they will not be regarded as a basis for special relief.[147] Such circumstances may include higher prices in other markets, "unusually high pressure, great volume, concentrated delivery points, delivery of large volumes at one point, unusually high gas quality, unusually good deliverability, and the availability of gas for swing purposes,"[148] and none of these nor the combination of any or all of them constitute a basis for special relief. We are of the opinion that that determination was correct and shall deny petitions which set forth such circumstances as a basis for special relief.

[2740]

C. *SMALL PRODUCERS*

The Commission did not make small producers re-

146. See pp. 72-76, *supra*.

147. 40 F.P.C. 530, 618-619 (1968).

148. 40 F.P.C. 530 at 619.

spondents to this proceeding as we have already issued regulations covering small producer sales.[149]

Since the Supreme Court reversed the Court of Appeals and affirmed the Commission's decision concerning small producers but remanded for further clarification, the small producer may collect the rate prescribed herein for those sales made from wells commenced on or after January 1, 1973, or pursuant to contract dated on or after January 1, 1973, for gas not previously sold in interstate commerce except pursuant to the previously mentioned emergency provisions, or pursuant to contracts where the sales were formerly made under contracts which expired by their own terms on or after January 1, 1973, without any refund obligation. The justness and reasonableness of rates in excess of the rates established herein which have been collected by small producers for sales within the scope of this proceeding will be considered in appropriate proceedings as necessary.

It is our intention that this order shall not affect the jurisdictional sales of small producers except in those cases where small producers seek certification of their jurisdictional sales pursuant to the regulations established by this order. The fact that a small producer seeks certification of one or more sales pursuant to this order does not prohibit him from making other sales pursuant to the regulations established in Order No. 428, as amended,

149. *Exemption Of Small Producers From Regulation,* Docket No. R-393, Order No. 428, 45 F.P.C. 454 (1971), *as amended,* Order No. 428-A, 45 F.P.C. 548 (1971), *reh. denied,* Order No. 428-B, 46 F.P.C. 47 (1971), reversed, *Texaco Inc., et al. v. FPC,* 153 U.S. App. D.C. 195, 474 F.2d 416 (1972), *cert. vacated* and *remanded FPC v. Texaco Inc., et al.,* Nos. 72-1990 and 72-1491, June 10, 1974.

provided the small producer's total jurisdictional sales do not exceed 10,000,000 Mcf per annum.

[2741]

D. *THE NATIONAL RATE*

The estimated "zone of reasonableness" for the cost of new natural gas supplies determined in this decision is approximately 37.54 to 42.74 cents per Mcf, exclusive of State or Federal production, severance, or similar taxes, Btu adjustment, fixed annual escalations, and gathering allowances. As adjusted for the 1.7 Tcf disparity in gas reserve additions the zone of reasonableness ranges from 37.01 to 41.90 cents per Mcf (Appendix C, Schedule, Sheet 1, Columns (d) and (e)). The Commission finds that a rate of 42.0 cents per Mcf, exclusive of State or Federal production, severance, or similar taxes, Btu adjustment, fixed annual escalations, and gathering allowances, constitutes a just and reasonable rate. This rate (42.0 cents per Mcf) is at a high level of the cost range which we have found to be reasonable after careful consideration of the record in this proceeding, and we find that it will provide the incentive necessary to encourage producers to undertake expanded exploration and development programs and to dedicate the natural gas discovered and produced as a result of those programs to the interstate market. In this section of the decision, we shall examine the effect of our conclusions upon the existing area rates, the consumer, and the producing industry.

The present area rates (rounded off), which are superseded by this opinion, are:

AREA	CENTS PER MCF (Exclusive of State Production Taxes)
Appalachian and Illinois Basin Area	24.0 - 34.0
Hugoton-Anadarko Area	19.9 - 20.0
Other Southwest Area	21.9 - 23.5
Permian Basin Area	32.4
Rocky Mountain Area	22.0 - 23.4
Southern Louisiana Area	23.7 - 26.0
Texas Gulf Coast Area	23.1

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The existing rate structure and moratoria for these areas are modified as previously set forth (pp. 99-100) in order to allow the collection of the rate prescribed herein to be collected with the appropriate waiver of refund credits and contingent escalations if necessary for the classes of gas sales which are the subject of this proceeding (p. 96).

We find increased rates established by this decision are necessary to allow for increased costs and declining reserve additions which have been reported since the issuance of the decisions in the various area rate cases. It is also necessary that we change the basic format of the rate structure so as to allow automatic adjustments (with proper notification to the Commission) for the derivative cost elements: production taxes and Btu adjustments. While it is possible to include such elements in the base area rate where the subject area is small and may cover parts of only a few states, we do not believe the same is true on a national basis where the several states all have different taxing policies and the quality of the gas may vary considerably.

1. *FIXED ANNUAL ESCALATIONS*

The just and reasonable base national rate established by this decision is 42.0 cents per Mcf, exclusive of the applicable production taxes, Btu adjustment, and applicable gathering allowances. Based upon the two production schedules utilized herein (Appendix F), the present value of a 1.0 cent per annum escalation over an eighteen year depletion period is approximately 5.0 cents per Mcf to 5.7 cents per Mcf.

The effective rate resulting from the addition of the present value of the fixed annual escalation of 1.0 cent per Mcf to the base national rate of 42.0 cents per Mcf is 47.0 cents per Mcf to 47.7 cents per Mcf. We realize that the two production curves which have been utilized to compute the present value of the fixed annual escalation will not apply to all reservoirs or wells exactly. Some wells or reservoirs will produce for a much longer period of time than others and that some reservoirs will be depleted or not producing for various reasons long before

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the end of an 18 year depletion period. Moreover, the rates of takes from various reservoirs will vary according to the producing characteristics of the particular reservoir and the need of the purchasing pipeline for gas supplies.[150] However, we believe that the production curves which have been used in determining the present worth of the annual escalations provide a reasonably reliable estimate of the present worth in most cases.

150. Many of the interstate pipelines with a need for additional gas supplies in recent years have accelerated their takes from many reservoirs and this will affect the present value of the fixed annual escalation.

The present value of the fixed annual escalations was computed by discounting the escalations at 15 percent[151] over a depletion period of 18 years. In Case I, it was assumed that the reserves found would be produced at a constant rate equal to 5.56 percent of the contract volumes per annum over the life of the depletion period (assumed to be 18 years). The present value of the 1.0 cents per Mcf annual escalation under these conditions is 5.0 cents per Mcf. In Case II, we utilized the production curve present in Appendix D to the "Initial Decision of the Presiding Examiner on Hugoton-Anadarko Area Rates," 44 F.P.C. 824, 991 (1970), to evaluate the present worth of the 1.0 cent per Mcf annual escalation. Since the production curve from Appendix D to the Examiner's decision is based upon a 37 year production period, we assumed that the volumes produced during the first eighteen years represent the total contract volumes. The percent of production was then adjusted to the percent of contract volumes delivered and the present worth of the annual escalations was calculated from this adjusted curve. These computations yield a present worth of 5.7 cents per Mcf.

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A fixed annual escalation of 1.0 cents per Mcf is necessary to offset existing inflationary effects upon the revenues received in future years by natural gas companies, to preserve the financial integrity of those persons selling natural gas in interstate commerce, and to help provide the capital which will be required in future years to finance the unprecedented exploration and development programs which will be undertaken to discover and produce

151. A discount rate of 15 percent was adopted so as to correspond to the rate of return allowed herein.

the volumes of natural gas needed to meet the reasonable demands of the nation's economy for a clean-burning, non-polluting energy source. Additionally, the fixed annual escalation will help interstate purchasers to compete with intrastate purchasers for available supplies of natural gas.

We believe that the present value of the fixed annual escalations and that the overall result of these escalations are just and reasonable and will be required by the present and future public convenience and necessity to insure that adequate supplies of natural gas will be made available to the interstate markets in this and future years. This country has endured an embargo on imports of basic energy sources such as crude and refined petroleum products and liquefied natural gas, and is still in the throes of a national energy crisis and a continuing natural gas shortage. The natural gas shortage will not be eased unless and until sufficient supplies of natural gas are found and made available to the interstate market. The only way that sufficient natural gas supplies will be found is through increased exploration and development programs and these programs can be conducted only if there are funds available to finance the programs.

The fixed annual escalations of 1.0 cent per Mcf provided by this order are required to help insure that the rates provided by this decision are just and reasonable and that the rates will help finance the programs needed to find and produce the supplies of natural gas which the country will demand in the future, and we adopt the same as part of the rate structure determined in this decision.

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2. *ASSOCIATED NATURAL GAS SUPPLIES*

The single uniform national rate prescribed by this

decision is applicable to associated-dissolved natural gas supplies (casinghead or oil-well gas) as well as non-associated natural gas supplies (gas-well gas). This application recognizes that only the sources of the two types of gas are distinguishable, and it provides additional incentive to natural gas producers to sell available natural gas supplies in the interstate market rather than the intrastate market.

The net effect of allowing the same rate for casing-head gas as for gas-well gas is to increase the overall return on investment with respect to natural gas sold in interstate commerce. This increase arises from the fact that the costs attributable to a property which produces only natural gas are not representative of the costs associated with natural gas produced from a property which yields both liquid petroleum products and natural gas. Since some of the costs of a property which produces both products are attributable to the liquid petroleum products as well as to the natural gas produced from the property, the producer benefits by receiving a higher rate for the natural gas so produced than he would if the costs associated with the property were allocated to both the liquid petroleum products and the natural gas. This higher rate in turn increases the average return the natural gas producer received on all of the gas which he sells in interstate commerce.

The importance of associated natural gas supplies is shown in Table 4. For the period of 1966 through 1972, associated-dissolved natural gas reserve additions accounted for 32.2 percent of the total natural gas reserve additions, and nonassociated natural gas reserve additions accounted for 67.8 percent of the total reserve additions. In terms

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of production, associated-dissolved natural gas production averaged approximately 4.0 to 5.0 trillion cubic feet per year or 23.4 percent of the total natural gas production for 1966 through 1972, while the production of non-associated natural gas ranged from approximately 13.0 trillion cubic

TABLE 4

Natural Gas Reserve Additions And Production On Annual Basis By Type Of Gas For 1966 Through 1972 Including Alaska

(Millions Of Cubic Feet)

Year	Gross Annual Reserve Additions		Annual Natural Gas Production	
	Nonassociated	Associated	Nonassociated	Associated
1966	17,036,596	3,183,836	12,925,701	4,565,372
1967	17,963,668	3,840,665	13,638,562	4,742,276
1968	13,979,377	(281,960)	14,739,944	4,633,483
1969	6,854,718	1,520,286	15,971,735	4,751,455
1970	9,340,296	27,856,063	17,115,026	4,845,778
1971	8,917,403	908,018	17,062,338	5,014,174
1972	7,812,083	1,822,480	17,693,057	4,818,841

() Negative Figure

Proven Reserves As Of December 31, 1972

Type Of Gas	Volume Of Reserves (Millions of Cubic Feet)	Percent Of Total
Nonassociated	186,072,643	71.1
Associated	75,541,412	28.9

Source: *Reserves Of Crude Oil, Natural Gas Liquids, And Natural Gas In The United States And Canada And United States Productive Capacity As Of December 31, 1972,* Volume 27, Published jointly by the American Gas Association, American Petroleum Institute, and the Canadian Petroleum Institute (May 1973).

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feet per year to over 17 trillion cubic feet per year or 76.6 percent of the total production for 1966 through 1972. Associated-dissolved gas reserves at the end of 1972 amount to 75.5 trillion cubic feet or 28.9 percent of the total reserves, and nonassociated natural gas reserves were approximately 186.1 trillion cubic feet or 71.1 percent of the total year-end reserves.

The data on production and annual reserve additions in Table 4 is shown for a series of years to arrive at a more reliable estimate of the percentage attributable to both classes than would result from the use of a single year.

The rate structure adopted in this decision is designed to encourage renewed exploration and development activities while at the same time protecting the natural gas consumer from excessive rates. Our duty with respect to these matters can be concisely stated:

> [T]he purpose of regulation is to insure that natural gas be distributed at the lowest possible price, that its private producers and distributors not reap windfall profits at the expense of the consuming public, and that allocation of this valuable resource be dictated by the interest of the public, rather than by the interest of its holders in private gain. At the same time, the public interest requires some assurance that, both now and in the future, the supply of natural gas will be sufficient to meet those uses for which, relative to other fuels, it is most valuable.

Public Service Commission for the State of New York v. F.P.C., 487 F.2d 1043 at 1097 (D.C. Cir. 1973), *cert.*

granted, vacated and *remanded,* Nos. 93-966, *et al.,* June 17, 1974. Thus, we must insure that the price received by the natural gas producer does not result in "windfall profits" while at the same time assuring that there will be an adequate supply to meet the demands generated by the more valuable uses of natural gas. *See FPC v. Hope Natural Gas Co.,* 30 U.S. 591, 603 (1944); *Colorado Interstate Gas Co. v. FPC,* 324 U.S. 581, 612 (1945) (Jackson, J., concurring).

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Against these guidelines, we assess our decision. First, the methodology by which the cost of new gas supplies is calculated is imprecise, and the various adjustments and allocations can cause reasonable experts to differ as to what these adjustments and allocations should be. *Austral Oil Company, et al. v. FPC,* 428 F.2d 407, 434 (5th Cir.), *cert. denied sub nom Municipal Distributors Group v. FPC,* 400 U.S. 950 (1970). We have based our cost analysis upon what we consider to be the most reasonable and reliable bases, assumptions, and data in the record of this proceeding and set forth in detail the reasons for our decision on each of the cost components and the derivation of the various allocation formulae. The adjustments we have made are directed to the high side of the reasonable cost range to encourage the greater development of the greatest quantity of gas reserves.

The increase in price over the existing area rates is "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *FPC v. Hope Natural Gas Co., supra,* 320 U.S. at 603. An indicia of whether the price established is sufficient "to attract capital" is its comparison with the

intrastate prices. While the prevailing prices in the several intrastate markets cannot dictate the price we promulgate by this decision, those prices do provide a guideline of the attractiveness of the interstate rate to gas producers operating on previously dedicated acreage within the domain of the several states. Appendix C to the notice of rulemaking issued in this docket indicated that intrastate prices for new sales were in the range of 40 to 50 cents per Mcf in many producing areas, and the responses of a number of parties state that in some areas intrastate sales have been made at prices of 50 cents or more.[152] Before adjustment for the quality of the gas, the state production taxes, and the gathering allowance, the national rate is 42.0 cents per Mcf. We think that this national rate is sufficient to compete with prices being offered in the intrastate markets for non-Federal domain gas. Furthermore, the

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biennial reviews and annual escalations provided by this decision give the Commission the necessary flexibility to adjust the national rate if sufficient new supplies of natural gas are not dedicated to the interstate market.

A comparison of the national rate determined by this decision with what has been characterized as the "commodity value"[153] of natural gas and the price of substi-

152. A number of parties to this proceeding state that intrastate prices in several areas may be substantially in excess of 50 cents per Mcf; that information does not give the number of sales at those prices, the volume of gas being sold, or the terms of the various contracts. Without such information, we cannot assess the presently prevailing level for new intrastate sales and decline to use such sketchy information as a basis for evaluating the rate established herein.

153. It appears that the "commodity value" of natural gas is calculated by determining the price and availability of substitute

tutable fuels shows a differential.[154] Even though the price of natural gas is less than the price of substitutable fuels, it does not follow that the prices must be equivalent or that the price of natural gas must be increased every time the price of other domestic or foreign energy sources is increased. To allow such increases would place the consumer at the mercy of pressures which dictate the price of other fuels but which bear no relationship to the cost of new gas supplies.

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The just and reasonable national rate for new natural gas supplies dedicated to the interstate market prescribed in this decision is founded on costs. In addition, the Commission has considered other relevant facts such as intrastate market prices, the "commodity value" of natural gas, and the cost of alternate fuels in evaluating the sufficiency of the cost-based rate. In our opinion, the rate prescribed herein is at a level which will serve the public interest by increasing the supply of natural gas available to the interstate market and which will affect a more efficient utilization and allocation of the nation's natural gas resources in an intercompetitive fuel economy.

fuels to the consumer, and subtracting a reasonable allowance for transportation and distribution to arrive at a field price for natural gas. *See* Appendix B to the Response of the Indicated Producer Respondents.

154. The claim of some respondents to this proceeding that the price of electricity is to be considered in determining the price of alternate fuels is rejected. Electricity is a secondary energy source that is produced by the consumption of primary energy sources such as natural gas, fuel oil, or coal. Electricity provides an important part of our nation's total energy consumption, but the fact does not require that the price of electricity be considered in determining the price of natural gas; indeed, it is noted that the price of electricity is substantially influenced by the price of primary fuels—coal, oil and natural gas—used to produce the electricity.

The provisions of Order No. 455 (*supra*, note 5) will continue as an optional procedure for the dedication of new natural gas supplies to the interstate market.

The test of eligibility for the national rate is similar to the standard established in Order No. 455 (18 C.F.R. §2.75(b)(1)) with significant differences as to the factors utilized to determine the rate level. The national rate is controlled by the predictive cost of finding and producing new natural gas supplies on a nationwide basis based on national averages. Under Order No. 455, costs are a point of departure to determine any higher rate which may be warranted by non-cost economic factors or by project costs.[155]

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IV.

ENVIRONMENTAL IMPACT

The Friends of the Earth, a national environmental organization, has filed comments contending that the Commission has failed to comply with the formal procedural requirements of the National Environmental Policy Act of 1959 (hereinafter NEPA)[156] by failing to prepare and circulate a detailed environmental impact statement as required by Section 102(2)(C) of NEPA.[157] Friends of the Earth contend that the preparation of a detailed environmental impact statement is mandatory in this proceeding, that "very little is known about the im-

155. *See, e.g., Texas Eastern Exploration Company,* ____F.P.C. ____, (May 15, 1974).

156. 83 Stat. 852, *et seq.* (1970); 42 U.S.C. §4321, *et seq.* (1970).

157. 83 Stat. 852, 853 (1970); 42 U.S.C. §4332(2)(C) (1970).

pact which higher natural gas prices will have on increasing supply," that "large utilities and industrial users [may be unable] to secure alternate supplies of non-polluting fuels should higher prices make it unprofitable for them to continue to burn gas as boiler [fuel], . . . [and] the impact which higher prices will have on offshore drilling for oil and gas." Friends of the Earth's contentions are misplaced for, although a detailed environmental impact statement was not prepared and circulated in this proceeding, this decision will discuss the possible environmental impact of the rate established herein in order to demonstrate the futility of attempting to quantify that possible impact upon the environment into a detailed environmental impact statement.

We submit that Congress did not intend NEPA to apply to a national gas rate proceeding. Even if NEPA is applicable we shall, nevertheless, state our reasons for concluding that a detailed environmental impact statement is not required in this proceeding pursuant to the mandate in *Arizona Public Service Company v. FPC*, ____ U.S. App. D.C. ____, 483 F.2d 1275 (D.C. Cir. 1973). NEPA does not always demand that the detailed impact statement required by Section 102(2)(C) be prepared by an agency where the agency sets forth its reasons why a NEPA statement is not necessary and "[t]he value of such a statement of reasons is becoming generally recognized as courts and agencies grapple with

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the difficult task of developing procedures for compliance with NEPA."[158] NEPA "is subject to a rule of reason,"

158. *Scientists' Institute For Public Information, Inc. v. AEC, et al.*, ____U.S. App. D.C.____, ____, 481 F.2d 1079, 1094 (1973);

and an "agency need not foresee the unforeseeable . . . "[159] Within this "rule of reason" and the scope of our jurisdiction under the Natural Gas Act,[160] we shall outline the various factors which combined render any attempt to reasonably predict the environmental impact of this decision a complete exercise in futility.

This proceeding must be examined as to its rather limited scope before any assessment of the applicability of the requirements of Section 102(2)(C) can be made. Under §§ 4, 5, and 7 of the Natural Gas Act the Commission has the power to establish rates and other conditions for the sale and transportation of natural gas in interstate commerce, but the Commission does not have the power to force a natural gas producer to search for gas in a particular location or to commence the sale of natural gas in interstate commerce at the rate which has been determined to be just and reasonable.[161] Nor do we have the power to "*order a natural gas company to sell gas to users* that [the Commission] favors; [footnote omitted] [we] can only exercise a veto power over proposed transportation and it can only do this when a balance of *all* the

See also Hanly v. Kleindienst, 471 F.2d 823 (1972), *cert. denied*, 412 U.S. 908 (1973); *Arizona Public Service Company v. FPC*, ____U.S. App. D.C. ____, 483 F.2d 1275 (D.C. Cir. 1973).

159. *Scientists' Institute For Public Information, Inc. v. AEC, et al., supra*, 481 F.2d 1079, 1092. Hereinafter *SIPI*.

160. NEPA is to be read in conjunction with the Natural Gas Act, and we note "that NEPA was not intended to repeal by implication any other statute." *United States, et al. v. Students Challenging Regulatory Agency Procedures (SCRAP), et al.*, 412 U.S. 669, 694 (1973).

161. *See, Atlantic Refining Co. v. Public Service Commission of New York*, 360 U.S. 378 (1959).

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circumstances weighs against certification." *FPC v. Transcontinental Gas Pipeline Corp.*, 365 U.S. 1, 17 (1961) (Emphasis supplied).

In the *SIPI* case, the Court outlined a series of questions which should be answered with respect to a statement of reasons where an impact statement is not prepared. *See*, ___ U.S. App. D.C. ___, ___, 481 F.2d 1079, 1092. Before these questions are considered, the parameters of the potential environmental impact should be outlined. Two major forms of environmental impact may occur as a result of the action taken herein: the first form of environmental impact likely to occur from an increase in the rates which natural gas producers are allowed to collect for their sales in interstate commerce is the impact associated with exploration and drilling activities; the second form of environmental impact is that associated with reallocations of the end use of natural gas in the various local energy markets due to changes in price and supply. Neither of these two forms of environmental impact are susceptible to precise quantification because of the uncertainties in predicting the effect of any given rate upon increased exploration and drilling activities by natural gas producers and the impossibility of predicting the increased supplies of natural gas which will be available to any given interstate pipeline and to all interstate pipelines as the result of any given level of exploration and development activity. Furthermore, the environmental impact in the various energy consuming marketplaces will depend upon the extent of curtailment being imposed by the interstate pipeline or pipelines serving the various marketplaces and the volumes of gas re-

quired by each of the different categories of customers in that marketplace. Each of these factors presents issues which cannot and should not be resolved in a producer rate proceeding, but rather must be resolved in the various pipeline curtailment proceedings to insure that all classes of natural gas consumers are treated equitably. In those cases, the environmental impact will be evaluated pursuant to the mandate in *Arizona Public Company v. FPC, supra.*

The Commission has only two options in this proceeding: continue the existing area rate structure with the existing prices which are based upon evidence and cost information

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as old as 1962 in some cases,[162] or update the existing rates to reflect more current cost and productivity trends. Once it is determined that the rates must be updated, the ultimate rate level determined to be just and reasonable depends upon the Commission's exercise of its expertise after consideration of all of the evidence and information contained in the record of the proceedings. Continuation of the existing area rates will only lead to further degradation of the already critical gas supply available to the interstate market. An increase in the rates allowed for sales of natural gas in interstate commerce should increase the volumes of new natural gas supplies which will be made available to the interstate market as we have previously noted in the section of this decision pertaining

162. *See, Area Rate Proceeding (Hugoton-Anadarko Area), et al.*, 44 F.P.C. 761 (1970); *Area Rate Proceeding (Texas Gulf Coast Area), et al.*, 45 F.P.C. 674 (1971); *Area Rate Proceeding (Other Southwest Area), et al.*, 46 F.P.C. 900 (1971).

to natural gas supply and demand, but those volumes cannot be quantified with any reasonable precision. Thus, a current review of the costs of finding and producing new natural gas supplies is the only viable alternative before the Commission in this proceeding. That is one option which the Commission has implemented by this decision.

The first question which the *SIPI* decision requires be considered by an agency is "To what extent is meaningful information presently available on the effects of application of the [decision] and of alternatives and their effects," 481 F.2d at 1092.

Implementation of this decision will result in increased exploration and development activity, the extent of such increased activity is not know and is not susceptible of meaningful quantification, with resulting environmental impact in the areas where such activity is conducted. The location and extent of such activity will further depend upon the results of the initial exploratory activity and the size of the gas reserves ultimately discovered or not discovered. This Commission has no

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authority to compel private entities to explore for, develop, and sell natural gas supplies in the interstate market; our jurisdiction merely extends to the regulation of the rates at which natural gas is sold in interstate commerce. Since we cannot compel a private entity to explore for, develop, and sell natural gas supplies in the interstate market, we cannot compel these private entities to explore for and develop new natural gas supplies in any given geographical area, and, as a result, it is impossible to determine in advance what environmental im-

pact will occur as a result of increased exploration and development activity or where within the continental United States such environmental impact will occur.

With respect to those new natural gas supplies which are located within the offshore Federal domain, we will know in advance what environmental impact will occur as a result of exploration and development activity undertaken to develop and produce those supplies because the Department of the Interior prepares a final environmental impact statement before particular blocks are proposed to be leased. An overall review of the environmental impact result from offshore drilling is currently being conducted by the Council on Environmental Quality. *See,* The President's Energy Message, April 18, 1973. These Department of the Interior statements are supplemented by the detailed environmental impact statements which this Commission requires before a major pipeline project to connect new offshore reserves is approved and construction allowed to commence.[163]

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With respect to those new natural gas supplies which are discovered in the onshore (and offshore) domains of the several states, we have no authority to compel the sale of those natural gas supplies in interstate commerce unless these newly discovered supplies are located upon acreage which has been previously dedicated to an inter-

163. 18 C.F.R. §§2.80, 2.81; *Implementation Of The National Environmental Policy Act of 1969*, 44 F.P.C. 1531 (1970), *as amended,* 45 F.P.C. 563 (1971), *as amended,* 46 F.P.C. 1240 (1971), *as amended,* Order No. 415-C, 48 F.P.C. 1442 (1972), *reh. denied,* 49 F.P.C. 359 (1973); *Implementation Of The National Environmental Policy Act of 1969,* Docket No. R-473, Order No. 485, 49 F.P.C. 1280 (1973).

These requirements apply to both onshore and offshore projects.

state pipeline company. This factor makes it impossible for the Commission to determine which exploration and development activities will be associated with a sale of new natural gas supplies in interstate commerce prior to the filing of an application for a certificate of public convenience and necessity authorizing the sale of natural gas to an interstate pipeline. We are, therefore, unable to predict in advance which drilling activities will ultimately result in the sale and transportation of natural gas in interstate commerce subject to this Commission's jurisdiction.

Implementation of an increase in the rates allowed for the sale of natural gas in interstate commerce may have some effect upon the ultimate end use of that gas in the various energy marketplaces. The ultimate end use of new natural gas supplies sold in interstate commerce is not readily definable since the Commission does not know in advance of the filing of an application for a certificate authorizing the sale of such new supplies of natural gas to a particular interstate pipeline which interstate pipeline will actually purchase these new supplies for resale. To be sure, all interstate pipelines will purchase new natural gas supplies as they are able to contract for such supplies; however, the prices paid by the various individual pipelines and the various classes of customers to which the different interstate pipelines resell natural gas and the various proportions of the volumes which are consumed in particular end uses vary from pipeline to pipeline. These variations plus the ability of the individual pipelines to acquire new supplies add to the difficulties to determining the environmental impact in the various energy consuming marketplaces which will occur as a result of an increase in the rates allowed for producer sales of natural gas in interstate commerce.

The extent of curtailment on the systems of the interstate pipelines and the nature of the resale customers is more likely to affect the ultimate end use of natural gas sold in interstate commerce than is an increase in the

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price allowed natural gas producers.[164] This Commission has already promulgated regulations establishing curtailment priorities; these regulations require that interstate pipelines curtail their customers by type of usage and volume rather than by geographic area unless special circumstances require relief from the curtailment priorities.[165] Thus, it is impossible to predict in advance what environmental impact will result from a given pipeline's curtailment plan since the plan is by its very nature a contingency plan subject to implementation and termination depending upon the pipeline's gas supply situation which may change from day to day. *Arizona Public Service Company v. FPC*, ____ U.S. App. D.C. ____, ____ F.2d ____ (D.C. Cir. No. 72-1636, January 2, 1974).

These regulations requiring curtailment by volume and type of usage seek to balance the need of residential and small commercial for a continued supply of gas while minimizing the adverse environmental impact that might

164. See Appendix B for the prices of different energy sources by region and usage.

165. 18 C.F.R. §2.78; *Utilization And Conservation Of Natural Resources—Natural Gas Act*, Docket No. R-469, 49 F.P.C. 85 (1973), *as amended*, 49 F.P.C. 217 (1973), *as amended*, Order No. 467-B, 49 F.P.C. 583 (1973), *reh. denied*, 49 F.P.C. 1036 (1973); *Utilization And Conservation of Natural Resources—Natural Gas*, Docket No. R-474, Order No. 493, ____F.P.C.____ (38 *Fed. Reg.* 2737, September 21, 1973), *as amended*, Order No. R-493-A, ____F.P.C. ____ (38 *Fed. Reg.* 30432, October 29, 1973).

result from requiring large volume industrial and utility consumers to use other fuels (18 C.F.R. §§2.78(a)(11)). We should point out that such allocations are more appropriately made in the context of individual pipeline curtailment proceedings rather than in the context of a

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producer rate proceeding.[166] The imposition of a pipeline by pipeline curtailment review in this proceeding to determine all of the possible environmental consequences that might possibly result from the increase in the rates allowed for the sale of gas in interstate commerce would so burden this proceeding as to make it impossible to establish just and reasonable rates as required by the Natural Gas Act.

Furthermore, to the extent that increased volumes of natural gas are made available to the interstate market as a result of this decision, pipeline transportation costs will be reduced by the increased throughput. A continued decline in the volumes of gas available to interstate pipelines will eventually result in higher costs to the consumer since the fixed costs will be allocated to smaller volumes of gas. The increase in the new supplies of natural gas which the interstate pipelines are able to purchase as a result of this order will help offset the increase in pipeline unit costs resulting from the declining volumes of gas being transported by the interstate pipe-

166. By reviewing the environmental impact in individual pipeline proceedings, we will be in a better position to determine the environmental impact upon the affected energy consuming markets than we can in this proceeding. Moreover, as we have stated, it is impossible to determine in advance which energy consuming market will obtain any given supply of gas that becomes available to the interstate market.

lines. The overall result, however, will most likely be a net increase in the cost of natural gas to the consumer since the increases in the pipelines' costs would be less than the increase in the rates allowed for producer sales of natural gas in interstate commerce which will be permitted by this decision.

In determining "to what extent . . . irretrievable commitments [are] being made" (*SIPI*, 481 F.2d at 1092) as a result of this decision, we must note that only

[2759]

private entities with supplies of natural gas available for sale through their exploration and development activities and the interstate pipelines desiring to connect those supplies will conceivably make commitments as a result of this order. Those commitments will also be made as the result of other factors such as intrastate market prices, the location of the gas reserves found through exploration and development activities, and the location of existing pipeline facilities. A natural gas producer makes an irretrievable commitment only to the extent that gas reserves are dedicated to the interstate market, and the interstate pipeline makes a commitment only to the extent incremental facilities such as gathering lines or compressors are installed to connect a new gas supply. If a major pipeline project is undertaken to connect new natural gas supplies, a detailed environmental impact will, of course, be required under Section 102(2)(C).

The Commission anticipates that additional exploration and development activities will be undertaken as a result of this order and that additional supplies of natural gas will be dedicated to the interstate market. There exists no

reliable methodology by which the location and extent of this exploration and development activity may be predicted, and we have no method for accurately predicting the volumes of new natural gas supplies that will be forthcoming at the rate established herein. *Placid Oil Company, et al. v. FPC*, 483 F.2d 880, 900-902 (5th Cir. 1973), *affirmed sub nom. Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U. S. June 10, 1974).

Thus, we can only conclude that there may be some adverse environmental impact as the result of increased exploration and development activity which is undertaken because of the decision in this proceeding. There may also be some adverse environmental impact as the result of pipeline projects undertaken as a result of the decision rendered in this proceeding. And there may be some adverse environmental impact in the energy consuming marketplaces due to an increase in consumption of other fossil fuels because of an increase in the price of natural gas and the extent of curtailment being imposed by the interstate pipelines. None of these potential adverse environmental impacts which may result from the

[2760]

increase in rates allowed by this decision is susceptible to any sort of reasonable quantification in this proceeding without resort to unreasonable speculation and conjecture. It may be possible, however, in proceedings concerned with the construction of a major pipeline project to connect new natural gas supplies to an interstate pipeline to determine the extent of the environmental impact which will result from that particular project.

Finally, it is not practical to determine "how severe will be the environmental effects" of the action taken

herein. *SIPI*, 48 F.2d at 1092. As previously noted, the environmental impact resulting from increased exploration and development activity will depend upon the location and extent of that activity. The Commission is not able to determine in advance the location and extent of exploration and drilling activity that will be undertaken as a direct or indirect result of this decision. Moreover, the environmental impact in the areas where natural gas is consumed as a fuel or an industrial feedstock will depend upon the end use of the gas. This, in turn, will depend upon each individual interstate pipeline's gas supply and curtailment situation and the availability and comparative cost of alternate fuels for each consumer. These factors will vary from pipeline to pipeline and from consumer to consumer. To the extent this Commission has control over such matters in certificate cases, the environmental impact should be examined there. But it is an absurdity to suggest that these matters must be disposed of in a producer rate proceeding. The environmental effects of all possible combinations of these variables would be mathematically impossible to compute, much less identify and measure, when the matter is approached in a rate proceeding designed to establish the ceiling price that can be charged and collected for sales of natural gas to interstate pipeline companies.

In view of the foregoing, the Commission is of the opinion that a detailed environmental impact statement outlining the ultimate effects of this order cannot be prepared without resort to unreasonable speculation and conjecture.

[2761]

V

DEEPER DRILLING AND DEEPER OFFSHORE WATER DEPTHS

Allowances for deeper drilling and an allowance for drilling in offshore waters of increasing depths are two matters which require further consideration by the Commission. The evidence in the record on these two matters is not sufficient to allow decision thereon.

As a substantial portion of the new natural gas supplies for the United States in future years will come from wells drilled to depths of 15,000 feet or more below the surface in the onshore areas and from offshore areas where the water depths will be increasingly greater than those being explored today, the Commission has concluded that some additional cost allowance may be necessary for these drilling efforts, but we do not find sufficient information, data and evidence in the record of this proceeding to determine the methodology by which a reasonable allowance can be justified for these projected additional costs and what amount (cents per Mcf) should be provided as the allowances for deeper drilling (in both the onshore and offshore areas) and deeper water depths in the offshore areas.

Because there is a lack of persuasive evidence in the record of this proceeding upon which to determine a reasonable allowance for deeper drilling or the increasing offshore water depths, we have concluded that the most appropriate manner of resolving these issues lies in our optional procedure or pursuant to applications for special relief. Those parties seeking a rate greater than the base

national rate established herein because of greater drilling or water depths should tailor the request for such price relief so that it may be evaluated on a cost basis. In such a proceeding all issues including the appropriate rate of return would be open to resolution.

[2762]

In suggesting that these matters be resolved on a cost basis for each particular applicant, we do not mean to suggest that each application on these grounds will be the subject of a formal hearing or that nationwide cost data is not relevant. What we are suggesting, and desire to state in no uncertain terms, is that the rates granted under the procedures set forth above will be rates adequate to cover all costs and provide a rate of return which is sufficient to compensate the applicant for the risk involved and not merely an allowance for the out-of-pocket expenses.[167] Moreover, we are of the opinion that an individual producer's data and costs would be more meaningful in these situations than nationwide cost data. Because of the nature of the ultradeep drilling,[168] there is not a large volume of nationwide cost and productivity data available for such drilling activity.[169] This lack of

167. See *supra*, as to our comments on special relief in general.

168. We use the term "ultradeep drilling" to refer to wells drilled to depths greater than 15,000 feet below the surface.

169. The 1972 JAS report noted only 125 oil wells, 159 gas wells, and 212 dry holes for wells drilled to depths of 15,000 feet or greater in 1972. The 1972 totals were 10,753 oil wells, 5,086 gas wells, and 10,604 dry holes for all depths. Thus, the super deep wells were less than two percent of the total number of wells drilled.

The GHK Company and Gasanadarko, Ltd. (GHK) made a cost presentation for super deep drilling based upon their individual experience in drilling such wells and upon 1972 JAS data. Since this presentation was limited primarily to the Deep Anadarko Basin, it does not provide the broad coverage necessary to make nationwide

data precludes any meaningful analysis of the cost of super deep drilling on a nationwide basis.

[2763]

There is also almost a complete lack of data on the productivity associated with the various drilling depths, and this lack of data further precludes the Commission from evaluating the appropriate productivity factor to be utilized in determining an allowance for ultradeep drilling. One party to this proceeding (The GHK Company and Gasanadarko, Ltd.) filed any evidence on the productivity of the ultradeep drilling.[170] The GHK data indicated that productivity factors for such drilling might be over 1,000 Mcf per foot drilled. We do not, however, believe that such a limited presentation provides a sufficiently comprehensive data base to determine a nationwide productivity for drilling at depths greater than 15,000 feet.

In view of the foregoing, we find that there is not a sufficiently comprehensive data basis upon which to establish a nationwide allowance for drilling and exploration efforts directed to the discovery and production of natural gas supplies located at depths greater than 15,000 feet below the surface. We further find that the rate for such gas supplies should be established for individual producers on a cost basis pursuant to petitions or applications filed with the Commission. Such petitions may be filed pursuant

cost findings. However, it is the type of presentation that we seek from individual companies seeking a higher rate for their deep drilling and exploration activities so that we may establish proper rates for such gas.

170. The American Gas Association does not report reserve additions by either reservoir depth for all reserves or by water depth for offshore reserves.

to the special relief procedures promulgated by this order or pursuant to the optional policy under Order No. 455 (see n. 4, *supra*).

In its comments submitted in response to the notice of rulemaking, Columbia Gas Transmission Corporation (Columbia Gas) urged the Commission to provide an allowance for the additional costs associated with drilling activities in the deeper water depths now being explored in the offshore areas.

[2764]

A number of other parties[171] filed comments which also supported Columbia's request for an additional allowance to compensate for the increased costs associated with the greater water depths.

As with the suggestion that the Commission provide an allowance for deeper drilling, there is little evidence in this record which can be utilized to quantify an allowance for greater water depths. The JAS report does not categorize offshore well costs by water depths, and the AGA does not report offshore reserves by depth below the ocean floor or by the overlying water depth. In such circumstances, no special allowance should set for the offshore water depths. But, we believe that individual producers should apply to the Commission for rates in excess of the base national rate established by this decision when the cost of an offshore project will yield a unit cost that is greater than the base national rate. Such applications will be treated in the same manner as those filed with respect to applications for increased rates based upon increased drilling depths.

171. Major Producer Group, AGD, UDC. See also comments of APGA and New York.

In closing, we believe that it is important to state the applications for special relief or under the optional procedure from the national rate based upon well depths greater than 15,000 feet[172] and

[2765]

increasing water depths will be considered on the total cost of the project including return on the invested capital. All such applications will be decided on an *ad hoc* basis to insure that each project is fairly treated.

Because of our conviction that extra cost allowances in addition to the base national rate may be necessary to encourage the development of deeper producing horizons both onshore and offshore, those producing horizons located in water depths greater than 250 feet, and previously unexplored areas such as the Atlantic coastal shelf, we intend to initiate such proceedings as may be required to accumulate the data and information necessary to compute the amounts of such allowances. Pending the initiation and completion of such proceedings, we will evaluate gas supplies from these special areas on a cost basis.

VI

SHORT-TERM AND EMERGENCY SALES

The Commission has determined that certain of its procedures permitting short-term and emergency sales should be rescinded or revised as of the date of this decision in this proceeding; those procedures which we

172. We shall adopt the suggestion of Kentucky West Virginia Gas Company that depths greater than 8,000 feet in the Appalachian and Illinois Basin Areas be accorded this treatment. Such treatment is consistent with Order No. 411. See 44 F.P.C. 1112, 1124 (1970).

shall rescind or revise are Sections 2.70 and 157.29 of the Commission's General Policy Statements and Interpretations and Regulations Under the Natural Gas Act insofar as those provisions allow (1) temporary emergency sales and

[2766]

(2) limited term sales with pre-granted abandonment.[173] The procedures set forth in paragraph 12 of the "Notice Expanding Notices of Investigation And Proposed Rulemaking To Nationwide New Gas Sales And Statement On New Applications For Certificates For Sales From All Areas" issued in Docket No. R-389-A on July 17, 1970,[174] shall also be rescinded as of the date of this decision in this proceeding. With the establishment of a single uniform national rate and the existence of the optional procedures under Order No. 455 (note 5, *supra*), it is no longer necessary to continue the emergency and certification procedures contained in those sections.

One purpose of this proceeding was to simplify the existing rate structure and the procedures for obtaining

173. 18 C.F.R. §2.70, *Policy With Respect To Establishment Of Measures To Be Taken For The Protection Of As Reliable And Adequate Service As Present Natural Gas Supplies And Capacities Will Permit,* Order No. 431, 45 F.P.C. 570 (1971), *as amended,* Order No. 431-A, 48 F.P.C. 193 (1972); 18 C.F.R. §157.29, *Exemption Of Temporary Sales Or Transportation,* Order No. 418, 44 F.P.C. 1574 (1970).

The 180-day provisions of these sections which were added by Order No. 491, *et al.*, note 4, *supra,* expired by the terms of Order No. 491 (*mimeo,* p. 7, Ordering Paragraph (D)) on March 15, 1974. *See* Order No. 491-D, ____F.P.C.____ (39 *Fed. Reg.* 8332, March 1, 1974). Prior to Order No. 491, §§2.70 and 157.29 allowed the performance of emergency action for only a 60-day period.

174. *Initial Rates For Future Sales Of Natural Gas For All Areas,* Docket No. R-389-A, 35 *Fed. Reg.* 11683 (1970).

a certificate to make sales for resale in interstate commerce. If we continue a myriad of certification procedures by which new supplies of natural gas may be dedicated to the interstate market, that purpose will not be accomplished. We are also concerned about the inordinate percentage of anticipated new deliveries to the interstate market for 1971 to 1973, which are traceable to our emergency and limited-term certificate

[2767]

procedures.[175] We have, therefore, concluded that §2.70 (b)(3) authorizing limited-term certificates with pre-granted abandonment and §157.29 authorizing temporary emergency sales by natural gas producers and the certification provisions in Paragraph 12 of the July 17, 1970, notice and statement in Docket No. R-389-A should be rescinded, as of the date of this decision.

We have determined, as a matter of policy, that applications for short-term dedications to the interstate market subject to pre-granted abandonment will not be certificated. The present gas shortage requires long-term solutions, not stop-gap measures. Thus, we have decided that the establishment of a just and reasonable national rate structure will be accompanied by a rescinding of certain existing emergency and limited term certification procedures. Certificates already issued under these procedures will not be affected by this action, however, new certificates will not be issued by the Commission.

Section 2.70 is modified by rescinding the provisions of §2.70(b)(3) pertaining to the authorization of limited-term certificates with pre-granted abandonment. Since the issuance of Order No. 431 which authorized limited-term

175. See Appendix G.

certificates, approximately 29.2 percent of the total anticipated deliveries of new gas supplies to the interstate market shown in Appendix G have been made pursuant to the provisions of §2.70(b)(3). We believe that the availability of these short-term dedications has caused producers of natural gas to defer entering into long-term dedications, and that, as a result, the long-term planning required to eliminate the natural gas shortage has also been deferred. The need for long-term dedications to the interstate market is apparent to us in order to assure the availability of a reliable supply of natural gas at reasonable prices and to enable producers, pipeline

[2768]

transmission companies, and distribution utilities to plan, finance, and construct the operating facilities required for continuation of reliable service. We have determined that the establishment of a single uniform national rate and procedure for a biennial review of that rate eliminates the need for our existing procedures under §2.70(b)(3) which provide for short-term deliveries to the interstate market, and we shall rescind §2.70(b)(3) as of the final order in this proceeding.

Section 157.29 is rescinded in its entirety. Section 157.22 provides sufficient exemption of temporary acts and operations where the pipeline has or is threatened with an interruption or serious curtailment of service due to the failure of facilities or a failure of the pipeline's normal gas supply. Also, the establishment of a single uniform national rate alleviates the need for regulations permitting the commencement of deliveries while the application for certificate authorization to commence the sales is pending before the Commission.

[2768]

The anticipated new deliveries to the interstate market which have resulted from the limited-term and emergency sales procedures of our regulations constitute approximately 47.7 percent of the total aggregate of new deliveries to the interstate market for 1971 through 1973. We are of the opinion that this percentage is inordinate, and should be reduced in favor of long-term dedications. To that end, we are eliminating the limited-term certificate provisions (18 C.F.R. §2.70(b)(3)) the emergency sales provisions for natural gas producers (18 C.F.R. §157.29).

[2769]

Paragraph 12 of the July 17, 1970, notice and statement in Docket No. R-389-A is being terminated since it was adopted as an interim measure adopted in that proceeding until a systematic rate structure was established. With the establishment of a single uniform national rate in this proceeding and the existence of the procedures under Order No. 455, we find no reason to continue the applicability of Paragraph 12, and the provisions found therein are terminated as of the date of the final order in this proceeding.

[2770]

The Commission further finds:

(1) Each respondent named in the notice of rulemaking in this proceeding is engaged in the sale for resale of natural gas in interstate commerce subject to the jurisdiction of the Commission and each is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission.

(2) The notice and opportunity to participate in this proceeding with respect to the matters presently before the Commission through the submission, in writing, of data, views, comments, and suggestions in the manner as described in this decision are consistent and in accordance with all procedural requirements therefor as prescribed in Section 553, Title 5 of the United States Code. Since the amendments proposed in this decision do not prescribe added duties or restrictions, compliance with the effective date requirements of 5 U.S.C. §553(d) is not necessary.

(3) The amendment to Part 2 of the Commission's General Rules to add a new Section 2.56(h) is necessary and appropriate for the administration of the Natural Gas Act.

(4) The amendments to Part 2 of the Commission's General Rules and Parts 154 and 157 of the Regulations Under the Natural Gas Act are necessary and appropriate for the administration of the Natural Gas Act.

(5) Information contained in the following documents should be included in the record of this proceeding, and these documents are hereby made a part of the record in this proceeding by incorporation:

Foster Associates, Inc., *The Impact Of Deregulation On Natural Gas Prices,* 1973.

Joint Association Survey Of The U. S. Oil & Gas Producing Industry, Sponsored by American Petroleum Institute, Independent Petroleum Association of America, and Mid-Continental Oil & Gas Association, December 1973.

Federal Power Commission Office of Economics, *Gas Supply Indicators—Fourth Quarter 1973 and Annual Review,* April 1974.

[2771]

Reserve Of Crude Oil, Natural Gas Liquids, And Natural Gas In The United States And Canada And United States Productive Capacity As Of December 31, 1972, Published Jointly by American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Volume 27, May 1973.

United States Department of the Interior, *Draft Environmental Impact Statement—Proposed Deregulation Of Natural Gas Prices,* July 17, 1973.

(A) *The Commission,* acting pursuant to the provisions of the Natural Gas Act, as amended, particularly Sections 4, 5, 7, 8, 14, 15, and 16 thereof (52 Stat. 822, 823, 824, 825, 828, 829, 830 (1938); 56 Stat. 83, 84 (1942); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. 717c, 717d, 717f, 717g, 717m, 717n, 717o) hereby *orders* that its General Rules Part 2, Subchapter A of Chapter 1, Title 18 of the Code of Federal Regulations, be amended by adding new Section 2.56(h), as follows:

2.56(h) National Rate For Sales Of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973

(1) Notwithstanding any other provisions in the General Rules of Practice and Procedure of the Federal Power Commission, or the Regulations Under the Natural Gas Act of the Federal Power Commission, sales of natural gas in inter-

state commerce made from wells commenced on or after January 1, 1973; or pursuant to contracts executed on or after January 1, 1973, for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Order No. 491); or pursuant to contracts executed on or after January 1, 1973, where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after

[2772]

January 1, 1973, within the United States may be made at a price not to exceed 42.0 cents per Mcf (at 14.73 psia), exclusive of state production taxes and subject to the adjustments herein provided.

The price prescribed by this paragraph may be increased by an amount not to exceed 1.0 cents per Mcf per annum commencing on January 1, 1974, and the first day of every year thereafter for the term of the contract dedicating the subject gas to sale for resale in interstate commerce pursuant to the terms of the contract.

[2772]

(2) For natural gas subject to the rate prescribed in Paragraph (1) of this section, quality standards and resulting adjustments to the base national rate shall be made in accordance with the provisions of the particular contract with respect to the contract rates, except:

[2773]

(i) Btu adjustment. For natural gas with more than 1,000 Btu's per cubic foot, at 60°F and 14.73 psia, upward adjustments shall be made on a proportional basis from a base of 1,000 Btu's per cubic foot, at 60°F and 14.73 psia, downward adjustments shall be made from a proportional basis from a base of 1,000 Btu's per cubic foot.

(3) Adjustment for taxes: The applicable rate shall be adjusted upward for all State or Federal production, severance, or similar taxes, effective the date deliveries are commenced, and shall be adjusted upward by 100 percent of any increase in existing State of Federal production, severance, or similar taxes subsequent to the date deliveries were commenced and shall be adjusted downward by 100 percent of any decrease in existing State or Federal production, severance, or similar taxes subsequent to the date deliveries were commenced.

[2774]

(4) The applicable national rate prescribed herein shall be adjusted for gathering activities as follows:

[2774]

(i) For natural gas produced from the Panhandle and Hugoton Fields of the Hugoton-Anadarko Area, the base national rate shall be adjusted upward 2.5 cents per Mcf where delivery is made at the tailgate of a processing plant, or at a point on the buyer's pipeline beyond the wellhead and beyond the central point in the field.

(ii) For natural gas produced from fields and reservoirs other than the Panhandle or Hugoton Fields of the Hugoton-Anadarko Area, the Permian Basin Area, and the Rocky Mountain Area, the base national rate shall be adjusted upward 1.0 cents per Mcf where delivery is made at the tailgate of a processing plant, or at a point on the buyer's pipeline beyond the wellhead and beyond the central point in the field.

(5) No seller may demand or receive any rate or charge in excess of the rate prescribed by paragraph (1), except for adjustments provided by paragraphs (2), (3), (4), and (7) unless the Commission after giving proper notice and

providing an opportunity for the submission of comments shall modify the rate set forth in paragraph (1).

(6) Any seller seeking to charge a rate in excess of the applicable rate or requesting a change in the applicable rate must file a petition for waiver or amendment of this section pursuant to Section 1.7 (b) of the

[2775]

Commission's Rules of Practice and Procedure (18 C.F.R. §1.7(b)) fully justifying the relief sought in light of this order. The seller may not file any rate increase in excess of the applicable rate herein prescribed unless and until the Commission grants the petition.

(i) For those cases where a producer seeks special relief on the grounds that a Federal income tax liability has been incurred with respect to the producer's jurisdictional natural gas operations, the producer shall submit certified copies of the appropriate Federal income tax returns and supporting schedules required by Treas. Regs. §§1.611-2 (g), 1.613-6 (26 C.F.R. §§1.611-2(g), 1.613-6) as part of the petition for special relief.

(ii) For sales of natural gas made from wells with a total depth greater than 15,000 feet (8,000 feet in the Appalachian and Illinois Basin Areas) and/or located in water depths greater than 250 feet, the seller may petition the Commission for relief from the rate established in paragraph (1) and such relief may be granted by the Commission upon a showing that total cost of producing such gas is in excess of the rate established in this decision. The applicant may make such a showing on a project, area, or company-wide basis.

[2776]

(7) If natural gas produced offshore is delivered onshore, at the sole cost of producer, the uniform national rate shall be adjusted upward 1.0 cent per Mcf for such offshore gas.

(8) The uniform national rate prescribed in paragraph (1), as adjusted pursuant to paragraphs (2), (3), (4), and (7), is the adjusted national rate and is applicable only to those jurisdictional sales within the United States (excluding Hawaii and Alaska) described in paragraph (1).

(9) To the extent that the Commission's Regulations Under the Natural Gas Act

establishing area rates and conditions for sale of natural gas from the Southern Louisiana Area (18 C.F.R. §154.105), Hugoton-Anadarko Area (18 C.F.R. §154.106), Appalachian Basin Area (18 C.F.R. §154.107), Illinois Basin Area (18 C.F.R. §154.109), Other Southwest Area (18 C.F.R. §154.109a), or Rocky Mountain Area (18 C.F.R. §§2.56(a), 154.109(b), and the Permian Basin Area are inconsistent with the provisions set forth above the same are hereby modified to reflect the provisions set forth above. The provisions of the rate structures for these are modified only with respect to those sales which are certificated pursuant to the provisions of this section and in all other respects remain in full force and effect. Provisions pertaining to refund credits and contingent escalations are contained in paragraph (11).

(10) The rate determined herein is applicable to the jurisdictional sales of natural gas described in paragraph (1), and shall remain in effect until June 30, 1976, or such earlier time as the rate shall be modified by the Commission after proper notice to all parties.

[2777]

(11) Any natural gas certificated under the provisions of this section which a natural

gas producer elects to have credited against his existing refund obligations in the Southern Louisiana, Texas Gulf Coast, or Other Southwest Area and the Permian Basin, or applied to the triggering volumes for the contingent escalations for those areas shall price that natural gas at the rate prescribed in the applicable area rate opinion and not at the uniform national rate prescribed in this opinion. For purposes of this section, the applicable area rate opinions and Commission regulations are:

(a) *Area Rate Proceeding (Texas Gulf Coast Area), et al.*, Opinion No. 595, 45 F.P.C. 675 (1971); 18 C.F.R. §154.109.

(b) *Area Rate Proceeding (Southern Louisiana Area), et al.*, Opinion No. 598, 46 F.P.C. 86 (1971); 18 C.F.R. §154.195.

(c) *Area Rate Proceeding (Other Southwest Area), et al.*, Opinion No. 607-A, 47 F.P.C. 99 (1972); 18 C.F.R. §154.109a.

(d) *Area Rate Proceeding (Permian Basin Area II)*, Docket No. AR 70-1 (Phase I), Opinion No. 662, ____F.P.C.____ (August 7, 1973).

[2777]

With respect to gas of a class described in paragraph (1), which is currently being sold in interstate commerce in discharge of a refund obligation or was dedicated to interstate commerce in partial satisfaction of the triggering volumes volumes for the contingent escalations in the described areas, such gas may be sold at the rate prescribed in paragraph (1) only if the seller files a written waiver of the right to discharge such refund obligations or to trigger the contingent escalations on or before September 21, 1974. The seller shall further state the date on which the subject wells were commenced, the present provisions under which the gas is being sold in interstate commerce, the dollar

[2778]

amount of existing refund obligations previously discharged by the sale of such gas, the volumes (at 14.73 psia) applied to trigger the contingent escalations.

(12) Any contractually authorized increased rate filing made pursuant to the provisions of this order shall be effective as of the date of issuance of this order, if the filing is made on or before September 21, 1974, and as of the date of filing if the filing is made subsequent thereto.

[2779]

(B) The Commission further orders that its General Rules, Part 2, Subchapter A, and its Regulations Under the Natural Gas Act, Part 157, Subchapter E, Chapter I of Title 18 of the Code of Federal Regulations be amended as follows:

(a) Section 2.70 of the General Policy Statements and Interpretations is amended as follows:

§2.70(b) (3) which reads as follows is rescinded in its entirety as of the date of this order:

(3) The Commission, recognizing that additional short-term gas purchases may be necessary to meet a pipeline's system demands for the immediate future, will continue the emergency measures referred to earlier for the stated 60-day period. If the emergency purchases are to extend beyond the 60-day period paragraph 12 in the notice issued by tne Commission on July 17, 1970, in Docket No. R-389-A should be utilized (35 F.R. 11683).

The Commission will consider limited-term certificates with pregranted abandonment, if the pipeline demonstrates emergency need, after complying with subparagraphs (1) and (2) of this paragraph.

[2779]

(b) Section 157.29 of the Regulations Under the Natural Gas Act is rescinded in its entirety as of the date of this order.

(c) The provisions of Paragraph 12 of the "Notice Expanding Notices Of Investigation And Proposed Rulemaking To Nationwide New Gas Sales And Statement On

New Applications For Certificates For Sales From All Areas" issued in Docket No. R-389-A on July 17, 1970 (35 *Fed. Reg.* 11683) are rescinded as of the date of the this order.

(d) Certificates already issued under the foregoing procedures will not be affected by this action; *Provided,* however, that applications for certificates pending before the Commission (including those upon which a hearing has been held or which are pending hearing) as of the date of this order will not be granted.

(C) This proceeding shall remain open for such other orders as the Commission may find appropriate.

(D) The Secretary of the Commission shall cause prompt publication of this Order to be made in the Federal Register.

(E) All persons, other than those named as respondents to this proceeding, who are named in the service list issued by the Secretary of the Commission on May 7, 1973, are hereby made parties to this proceeding.

By the Commission.

Commissioner Brooke, concurring, filed a separate statement appended hereto.

(S E A L)

Commissioner Moody, dissenting in part and concurring in part, filed a separate statement appended hereto.

Commissioner Smith, concurring, filed a separate statement appended hereto.

Kenneth F. Plumb,
Secretary.

[2780]

Just And Reasonable National Rates For Sales Of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973) Docket No. R-389-B

(Issued June 21, 1974)

BROOKE, Commissioner, *concurring:*

Mobil Oil Corporation in its supplemental comments of May 29, 1974, quoted this bit of rhyme:

"Second verse
Same as the first,
Could have been better,
But it only got worse."

Perhaps it should have been modified thusly:

"Second verse
Same as the first,
Could have been better
But thank Heaven it wasn't worse."

I am concurring in issuance of this landmark national rate order for two basic reasons:

(1) The rate prescribed is an improvement over myriad existing rate levels, and, as such, is partial recognition of the influence of price on the need to increase the availability of domestic supplies, and

(2) The public interest requires issuance of a national rate order without further delay.

However, I have great trouble with the methodology, as well as the result. Undoubtedly, the rate should provide

improved incentives in the search for new gas supplies. The substantial evidentiary support for the 42-cent (now escalated to a 43-cent) rate would also, in my opinion, support a higher and more realistic rate level. The rate prescribed herein falls at the upper end of the zone of reasonableness derived pursuant to the Commission's now institutionalized, but out-dated, area rate costing methodology.

[2781]

In relying entirely on the output of the costing model, the Commission ignores weighty evidence that rigid adherence to cost-based regulation *a la* Permian I sired the natural gas shortage and then nourished its growth to a mature national crisis. The legacy of wellhead rate regulation, initiated during a time of plentiful supplies in a "buyer's market" and now completely unresponsive to shortages, has been a worsening chronic gas supply, starkly illustrated by the inability of the industry to meet either existing firm or growth demand.

The relationship of price and supply is rather dramatically underscored by the fact that reserve additions of new non-associated gas supplies have run side by side with the steady attrition in real prices for new interstate gas over the past 15 years. Meanwhile, the unregulated intrastate market gives us a true picture of the actual value of natural gas.

Considerable controversy has attached to the data compiled by the American Gas Association, and this order attempts to deal with the discrepancy between certain AGA reserves reporting and Commission Staff's figures for the same tracts. I don't believe that any two sets of statistics will ever coincide precisely, but what is significant about AGA reserve data and FPC Form 15 informa-

tion is the downward trend. Lines plotting AGA proven reserves and Form 15's reserves committed to interstate pipeline run a parallel course, sharply downward. By any statistical evidence, the interstate system has been living off inventories the past several years, with but negligible, almost zero, additions to reserves.

It is this downtrend that we are trying to arrest and reverse, and the situation will only worsen if we continue that impossible search for the "right" price or the "right" rate. The record before us, I believe, sustains the statutory requirement of a "just and reasonable" national rate as well as being required by the present or future public convenience and necessity. Although I believe the cost-based determination plus reasonable non-cost add-ons would yield a rate equally "just and reasonable," the "rightness" of the rate can only be judged by industry performance.

The order extends lengthy discussion to the rationale underlying each component of the costing model, but it should be apparent that pure introspective judgment has permitted the arbitrary selection of certain variable components which, depending on the selection, can run the rate up and down like

[2782]

a yo-yo. Productivity is a major example, wherein justifying the span of years used or the revisions made does little more than reflect human judgment—and error.

This exercise in statistical juggling does little more than project the costing model's so-called zone of reasonableness —a range with high and low numbers which represent rates at the assumed maximum and minimum productivity figures, providing this is the only component subject to variation.

The upper and lower rate figures represent the "pure" cost-based zone of reasonableness within which the national rate was pegged. The national rate of 42 cents, as of January 1, 1973, since it is wholly predicated on costs, should be regarded as the point of departure for "a" rate and not regarded as "the" rate.

The mischief of the rate herein prescribed is that no consideration has been given to adjusting the cost-based rate with those non-cost factors the courts have construed as legitimate rate-making add-ons. The so-called "pragmatic adjustments" are woefully lacking.

As stated at the outset, the rate is an improvement—a step in the right direction that does not quite go far enough. I presume that the Permian I methodology is the best foundation we have for prescribing producer rates, excepting deregulation, of course, but apparently the Commission has learned little from 20 years of sad experience. We should have more regard for the real world—that supply inventories are declining each year, that inflation makes the assembly and commitment of capital more difficult without adequate incentives, that *sustained* exploration and development depend on realistic and adequate pricing policies without uncertainty, that total energy and environmental demands accelerate the value of natural gas as a premium fuel, that commodity value cannot be completely disregarded, *ad infinitum*.

Commissioner Moody has gone to exceptional lengths in questioning the methodology, and I concur largely in his observations.

/s/ ALBERT B. BROOKE, JR.
Albert B. Brooke, Jr.
Commissioner

[2783]

Just And Reasonable National Rate For	)	
Future Sales Of Natural Gas From	)	Docket No.
Wells Commenced On Or After	)	R-389-B
January 1, 1973	)	

(Issued June 21, 1974)

MOODY, Commissioner, *dissenting in part and concurring in part:*

A majority of the Commission will not acknowledge that *Permian I*[1] cost estimation is inaccurate and unreliable and should be discarded; this is a matter of administrative discretion[2] which lies within the province of the Commission to decide, and it is not likely that a reviewing court will tell us that we *must* discard *Permian I* methodology.[3] Accordingly, I see no point in arguing here the folly of perpetuating a demonstrably unworkable formula. I have made my arguments and they have failed of persuasion. As to this aspect of the case, I record my dissent without further comment.

This is not to say, however, that the majority order should be adjudged nonreversible because it represents the exercise of expert administrative judgment. Quite the contrary. The majority rate order is most inexpert; it will not withstand judicial scrutiny.

1. *Permian Basin Area Rate Proceeding,* 34 FPC 159 (1965), affirmed 390 U.S. 747 (1968).

2. *F.P.C. v. Natural Gas Pipeline Co.,* 315 U.S. 575 (1942); *Permian Basin Area Rate Cases, supra.*

3. *Cf. Mobil Oil Corp. v. F.P.C.,* ____U.S.____, No. 73-437, slip opinion issued June 10, 1974.

For purposes of demonstrating that the majority has set an unjust and unreasonable rate, I accept *Permian I* methodology. This dissent assumes the validity of the method, and

[2784]

question only the factual application of the *Permian I* formula to the particular record before us.

It is my firm conviction that the majority's 42¢/Mcf base rate cannot be supported on appeal, because it is without support in the record. In particular, the majority's rate order:

1. Understates the cost of 1973-1974 new gas supplies by such a wide margin that the "zone of reasonableness" is violated;
2. Provides an inadequate rate of return on invested capital to meet the comparable earnings test of utility regulation;
3. Impermissibly violates the mandate of the Supreme Court in *Permian* to look at factors other than current and projected costs in setting wellhead rates;
4. Produces end results wholly incompatible with the Commission's obligation to elicit an adequate and reliable supply of natural gas at the lowest reasonable cost to the consumer.

Each area of legal infirmity will be addressed separately.

I. Cost Estimates—Sins of Commission and Sins of Omission

On the path to its determination of a 42¢/Mcf base rate, the Commission must make analytical and factual

findings on the various cost components, the sum of which yield the final rate. The components chosen by the majority, consistent with *Permian I,* as recoverable in the base rate are:

1. Successful Well Costs
2. Recompletion and Deeper Drilling Costs
3. Lease Acquisition Costs
4. Other Production Facilities
5. Dry Hole Costs
6. Other Exploration Expense

[2785]

7. Exploration Overhead Expense
8. Operating Expense
9. Regulatory Expense
10. Royalty Payments
11. Return on Invested Capital
12. Return on Working Capital

The record before us impels the conclusion that the majority's 42¢/Mcf base rate results from an understatement of every cost component listed, with the exception only of return on working capital, operating expense, regulatory expense, and royalty payments.

A. *The record does not support the cost estimates indulged in by the majority.*

In order to demonstrate that the majority's base rate determination is not supported by the evidence before us, even assuming that *Permian I* cost estimation is proper, it is necessary to recall that in *Permian I* an attempt was made to adapt traditional utility ratemaking to producer rate regulation. To avoid problems of allocation of costs between oil and gas (a task recognized as impossible),

Permian I focused on industry average costs of finding and producing gas-well gas. From available data, *Permian I* constructed a hypothetical industry-wide rate base, comprised of investment in successful gas wells, in new leases, and in production facilities. Current expenses for dry holes, other exploration expense and overhead were estimated, and a rate per Mcf was then calculated which was intended to include:

A return of capital.
A return of current expenses.
A return on invested capital.
A return on working capital.
Reimbursement for royalty payments.
Reimbursement of a portion of production taxes.

The desired end result of *Permian I* new gas cost estimation was to arrive at a rate which would operate prospectively, and which would predict future capital and operating costs with sufficient accuracy so that an acceptable industry-wide

[2786]

program of exploration and development would result at a cost consistent with the utility ratemaking concept of recovery of costs plus a fair rate of return.

The rate order here seeks to fullfill the same office. The rate of 42¢/Mcf found by the majority to be just and reasonable is a rate for gas produced from wells commenced during 1973 and 1974, determined on a record that contains *no cost evidence* for either 1973 or 1974. It is, therefore, a rate based on an estimate of future costs and nothing more.

If the cost estimates of the majority order bore any reasonable relation to the evidence before us, my dissent would be one related to judgmental factors only. But this is not the case. The majority order estimates that the cost of new gas in 1973 and 1974 will fall between 37.54¢/Mcf and 42.7¢/Mcf. (Opinion, p. 96.)

The 42.7¢/Mcf cost estimate is predicated on these basic factual assumptions:

(1) Productivity during 1973 and 1974 will average 485 Mcf/ft.

(2) Successful well drilling costs during 1973 and 1974 will average $27.54/ft.

(3) Dry hole drilling costs during 1973 and 1974 will average $16.94/ft.

(4) The ratio between lease acquisition costs and costs of production will be .6740.

(5) The ratio between lease acquisition costs and other exploratory costs will be .6844.

The productivity prediction is based on a simple average of the past seven years actual result. The two drilling cost predictions are based on 1972 actual costs. The ratio predictions are based on averaging of the past seven years actual results.

The 37.54¢/Mcf cost estimate set forth in the majority opinion is built on the same predictions, with one exception.

[2787]

The 37.54¢ study predicts that productivity during 1973 and 1974 will average 552 Mcf/ft. This prediction is

based on averaging of productivity over the past 10 years.

The net result of the majority's order is to predict that the cost of bringing new gas to market during 1973 and 1974 will fall between 37.5¢ and 42.74¢. The order thereupon moves to the high end of the predictive range (for incentive purposes) and concludes that a 42¢ base rate will recover costs and permit a 15 percent rate of return.

The predictions upon which the majority order is based are not factually supportable under the record before us. In trying to assess what is reasonably probable by way of estimated new gas costs for 1973 and 1974, we cannot ignore the following considerations:

1. *The productivity prediction is insupportable.*[4]

The majority opinion deals with two basic data series covering the productivity of the gas drilling effort over the past 26 years, with both series set forth in Appendix C, Schedule 2. The majority concedes that drilling results more than ten years old have no place in a reason-

4. Not the least cause of my disenchantment with *Permian I* costing is its total dependence on an accurate prediction of productivity. "Productivity", as the FPC uses the term, is not readily measurable, nor is it easily predictable. The volume of proved reserves added, whether estimated by AGA, the FPC, or anyone else, will always involve judgmental calls, and will, therefore, always be open to question and criticism. The lack of time correlation between drilling footage reported and the estimation of reserves added further undermines a reliable productivity calculation. Averaging over a period of time does tend to smooth out some of the rough spots, but averaging introduces another distortion—the lack of correlation between the average and the series trend. In an era of rising productivity, averaging will always understate productivity, while in a time of declining productivity, averaging will always overstate productivity.

able estimation of future drilling results (Opinion, pp. 50-51; 53; 57). I agree. Accordingly, by consensus, the maximum relevant productivity series are:

[2788]

	AGA/World Oil Mcf/ft.	AGA/AAPG Mcf/ft.
1963	542	N/A
1964	674	N/A
1965	736	N/A
1966	630	660
1967	806	830
1968	614	610
1969	318	290
1970	472	410
1971	427	380
1972	286	280

I think it clear that we are legally obligated when we use *Permian I* costing to base our estimate of 1973 and 1974 productivity upon the most recent reliable data in the historic series if the record before us permits the conclusion that the immediate future cannot reasonably be expected to differ from the experience of the immediate past. The majority, not fully trusting the reliability of the past four years data, because of (a) negative revisions in 1969, 1970, 1971 and 1972 (Opinion, pp. 52-53) and/or (b) the possibility that 1971 and 1972 reserve additions may be understated by a total of 1.7 Tcf (opinion, p. 47), turns to a seven-year average as the basis for its high cost estimate of expected 1973 and 1974 productivity, and an averaging over 10 years for its low cost estimate of 1973 and 1974 productivity.

There is not one shred of evidence that 1973 and 1974 productivity will bear any relationship to the productivity *average* of the last seven years. There is evidence that the *trend* of productivity achieved in the past seven years may be reasonably expected over the next two years.

[2789]

May we rely upon the reported productivity of the past four years for any purpose? I believe so, if we are attempting to determine trend lines and reasonable predictions, as opposed to an arithmetic absolute. If we adjust the data for the two areas of uncertainty noted in this record, we can gauge whether any change in the seven-year down trend is discernible. As to the first area of uncertainty—the question of negative revisions—Appendix A establishes that this problem (if it is a problem) exists only in the years 1969, 1970, 1971 and 1972.

The second area of concern—the 1.7 Tcf disparity—affects only 1971 and 1972. If we indulge in a total acceptance of the premise that *all* negative revisions should be ignored and that *all* of the 1.7 Tcf reserve disparity should be included, we find the following:

	AGA Net Reserves Added (a)	AGA Negative Revisions (b)	Reported Disparity (c)	Adjusted Reserve Additions (a)+(b)+(c)
1969	6,874,718	(1,440,196)		8,314,914
1970	9,351,316	(290,034)		9,641,350
1971	8,565,403	(1,471,410)	(850,000)	10,886,813
1972	7,597,270	(1,911,097)	(850,000)	10,358,367
			1,700,000	

The productivity data series, after the foregoing adjustments, then becomes:

	Reserves Added (a)	AAPG Successful Footage Drilled (b)	Productivity (AAPG) (a÷b)
1969	8,315	24,064	350
1970	9,641	22,852	420
1971	10,887	22,609	480
1972	10,358	26,743	390

with the average productivity for the most recent four-year period being 410 Mcf/ft.

[2790]

It is thus clear that the *trend* of the past seven years is still downward:

	Productivity AGA/AAPG
1966	660
1967	830
1968	610
1969	350
1970	420
1971	480
1972	390

I invite a comparison of the majority's high-low productivity range of 485-552 Mcf/foot with the productivity experienced in each of the past four years after resolving every doubt in favor of adjusting these productivity results upward. The majority is in the indefensible posture of predicting that 1973-74 productivity will be greater than that experienced in any of the past four years, and greater than the average of the past four years. For this prediction to have legal validity the majority must articulate—on the basis of the record—why, and how they foresee such

an abrupt and dramatic improvement in drilling success. I submit that they have not done so.

As the use of a 552 Mcf/ft. productivity in the majority's low cost estimate amply demonstrates, a downward bias in the cost estimation process is introduced when reliance on remote data occurs. The more remote the productivity data, the greater the downward bias. In our efforts to set a *prospective* rate, a rate which must predict as accurately as possible the cost experience which will result in 1973 and 1974, the vice of looking to the remote past is evident. I submit that there is no basis in fact or in logic for the majority's claim that the *average* drilling results experienced in 1947 through 1968 has a reasonable relationship to what we may reasonably expect in 1973-1974. The record is devoid of evidence to support this claim.

[2791]

The majority acknowledges that there is a demonstrable downward trend in productivity over the recent past (Opinion, pp. 52-53), as indeed they must in the light of Appendix C. Having officially found that such a trend exists, the majority nonetheless predicts that the trend line will be broken in 1973-74; that productivity during the next two years will exceed that of the previous four. Upon what record evidence is this determination based,

I belabor this point because of the critical impact of the productivity prediction upon the whole of the rate structure. Productivity determines the allowance for successful well costs, which in turn affects the allowance for lease acquisition costs and the allowance for production facilities; productivity also determines the allowance for dry hole costs, which affects the allowance for exploration

overhead expense; and so on, virtually *ad infinitum. If we err in predicting productivity, we destroy the integrity of the whole rate structure.* Change the productivity prediction, and leave every other rate issue unchanged, and the final rate determination will vary dramatically. Appendix C graphically demonstrates the truth of this observation. Cost estimates of 1973-74 costs vary from 32.26¢/Mcf to 60.31¢/Mcf—a range of almost 100 percent—dependent largely on the productivity prediction employed.

When the majority enters its findings on an issue of such critical importance as the productivity prediction, it clearly must explain how the prediction is made and upon what record evidence it is based. Only then can a reviewing court truly judge whether our ratemaking is reasonably related to the evidence before us or whether we engage in a metaphysical exercise involving extra-sensory perception.

The overwhelming weight of the credible evidence before us teaches that 1973-1974 drilling results are more likely to relate to the 1966-1972 trend line experience than to any arithemetic averaging of previous years' results. There is no evidence that any averaging process will comport with the seven-year downtrend. If we are to base our rates upon this record, we must, therefore exercise our judgment in terms of the historic data which is relevant to our estimate of the immediate future. The relevant time span is shown to be no more than the preceding seven years, but the data for these

[2792]

years are relevant, as a predictive tool, only in terms of trends. An *averaging* of seven years' data produces a re-

sult contrary to the seven-year trend, and hence, an unreliable figure.

The trend line projection for 1973-1974 productivity is 381 Mcf/ft.[5] Rather than accept this as an absolute prediction, I would recognize the probability of yearly fluctuations, upward and downward (See Chart I, p. 56, majority opinion), and estimate a probable productivity range of trend line + – 10 percent, thus arriving at a range of 340 Mcf/ft. - 420 Mcf/ft. as a reasonable expectation for 1973-1974 results.

2. *The majority's cost predictions are insupportable.*

Drilling and Related Costs: The majority is predicting that 1973-1974 drilling costs will be:

Successful well drilling costs	$27.54/ft.
Dry hole drilling costs	16.94/ft.

The majority's cost estimations—both low and high—explicitly assert that successful gas well drilling costs and dry hole drilling costs in 1973-1974 will be equal to 1972 drilling costs. There is no evidence to support this factual determination, nor to support as an expert opinion this estimate as reasonably probable. All evidence in the record as to cost trends, and cost expectations, is that drilling costs will be higher in 1973-74 than they were in the preceding years.

The notion that last year's drilling cost is "current cost" and that future cost will be no greater is a major fallacy that exists in the majority opinion. It is doubly repugnant since so much of the remaining cost components are related to or dependent upon drilling costs.

5. Appendix D, Producer Respondents' Initial Comments.

Industry technicians have repeatedly forecast that the future

[2793]

prospects for gas will be at deeper horizons, offshore in steadily increasing water depths, and in remote areas. No one seriously disputes these forecasts. The virtual certainty of increasing costs is ignored by the majority. When they predict that costs will decline, surely they must relate this finding to the record and demonstrate why they so conclude.

Lease Acquisition and Related Costs: The majority's cost estimations—both low and high—explicitly assert that the 1973-1974 relationship between lease acquisition costs and other costs components will be the same as the average ratio based on the previous seven years. There is no evidence to support this view, and indeed, it is dramatically opposed to the demonstrated and proven sharp increase in lease acquisition costs which is proven in this record.

The lease acquisition cost component is one of the most volatile items in the *Permian I* costing formula, and is extremely sensitive to the effect of the huge bonus bids in Outer Continental Shelf lease sales. The dramatic increase in these costs in 1972, 1973 and 1974 over all prior years is totally ignored by the majority. The data for lease acquisition costs offshore are:

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OUTER CONTINENTAL SHELF LEASE SALES
As of June 7, 1974

Date		State	Acres Offered	Acres Leased	Total Bonus
10-13-54		Louisiana	748,000	394,721	$ 116,378,476
11- 9-54		Texas	111,788	67,149	23,357,029
7-12-55		Texas	216,000	149,760	8,437,462
7-12-55		Louisiana	458,095	252,807	100,091,263
2-26-59		Florida	458,000	132,480	1,711,872
8-11-59	*	Louisiana	81,813	38,820	88,035,121
2-26-60		Texas	437,760	240,480	35,732,031
2-26-60		Louisiana	1,173,223	464,046	246,909,784
3-13-62		Louisiana	1,808,276	951,811	177,260,305
3-16-62	*	Texas	90,720	28,800	557,720
3-16-62		Louisiana	1,780,265	927,746	267,775,727
10- 9-62	*	Louisiana	33,855	16,178	43,887,359
5-14-63		California	669,777	312,945	12,807,587
4-28-64	*	Louisiana	34,028	32,673	60,340,626
10- 1-64		Oregon	836,134	425,433	27,768,772
10- 1-64		Washington	253,940	155,420	7,764,928
3-29-66	*	Louisiana	35,993	35,056	88,845,963
10-18-66	*	Louisiana	227,898	104,717	99,164,930
12-15-66	*	California	1,995	1,995	21,189,000
6-13-67		Louisiana	971,489	744,456	510,079,178
2- 6-68		California	540,609	363,181	602,719,262
5-21-68		Texas	728,551	541,304	593,899,046
11-19-68	*	Louisiana	46,824	29,682	149,868,789
1-14-69	*	Louisiana	96,389	48,505	44,037,339
12-16-69	*	Louisiana	93,764	60,153	66,908,196
7-21-70	*	Louisiana	73,360	44,642	97,769,013
12-15-70		Louisiana	593,485	546,398	845,877,860
11- 4-71	*	Louisiana	55,872	37,222	96,304,522
9-12-72		Louisiana	366,682	290,321	585,827,925
12-19-72		Louisiana	604,029	535,874	1,665,519,631
6-19-73		Texas	697,643	547,173	1,591,397,380
12-20-73		Alabama, Florida & Mississippi	817,397	497,108	1,491,617,119
3-28-74		Louisiana	930,918	421,218	2,092,510,854
5-29-74		Texas	1,355,678	565,112	1,471,851,831
TOTALS			17,430,250	10,005,386	13,334,203,900

*Drainage sales.

[2795]

In dealing with the costs of lease acquisition, the majority utilizes a statistical average of the last seven years expenditures as reported by the JAS. This yields an average of slightly over $1 billion per year, and that is the sum the majority projects as being representative of the 1973-1974 cost for this component. The record proves the error of their estimate. Bonuses for OCS lease sales, which are only a part of this cost, have totaled $5.3 billion for the 1972-1973 period. We have already seen over $2 billion committed in the first quarter of 1974. A rate predicated on lease acquisition costs of $1 billion annually is totally inadequate.

The majority also predicts that lease acquisition costs incurred in 1973-1974 will bear the same ratio to production costs in 1973-1974 as was demonstrated on an average basis for the past seven years, and that the lease acquisition cost/other exploratory costs ratio for 1973-1974 will be the same as was true on an average basis for the past seven years.

None of these predictions can be supported by record evidence.

The majority is content to make mechanical use of averaging of prior years' expenses and productivity as a basis for its rate determination. I submit that this is legal error when the record before us conclusively proves that the use of averaging produces a prediction of tomorrow's costs that bears no reasonable relation to the actual cost and productivity results that are reasonably foreseeable.

3. *Ignoring productivity and cost trends is suicidal.*

Permian I methodology constructs wellhead rates

through a formula involving estimated costs and estimated productivity. If productivity rises above the estimated level the rate overstates costs, but if productivity falls below the estimated level the rate understates costs. Similarly, actual cost experience may make a liar out of the Commission's estimates, either on the high or low side.

The situation which this record makes unmistakably clear is that productivity is trending downward at the same time

[2796]

that costs are trending upward. The majority's rate says that both trends will break in 1973-1974; productivity will increase and costs will remain constant or decline.

Would that this were to become true. But if we adhere to the record, there is no basis for believing that it will, other than wishful thinking.

The combined effect of the majority's predictions on productivity and costs is to grossly understate the rate necessary to cover reasonably anticipatable 1973-1974 costs. The majority comes to this result because of a misplaced, and mechanical, application of a seven-year averaging technique to all cost data except successful well costs and dry hole costs where 1972 actual figures are plugged into the formula.

I submit that there is more involved in cost estimation than this.

We have before us a discrete data series setting forth actual historic cost experience. See Appendix C, Schedule No. 3, which reflects:

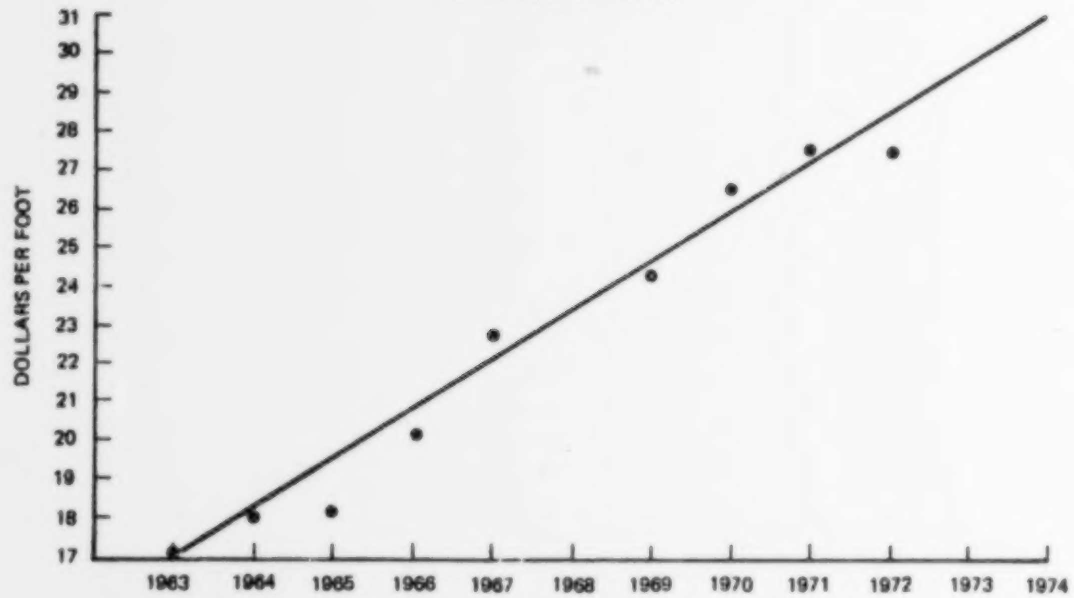
JAS DATA COMPARISONS

Year	Gas Well Drilling Costs/ft.	Dry Hole Costs per foot	Lease Acquisition Costs $ million	Other Exploratory $ million	Dry Hole Expend. $ million	Total O & G Well Exp. $ million	Exploratory Overhead
1963	17.11	10.42	376	679	790	1513	
1964	18.10	10.54	570	685	854	1574	
1965	18.16	11.16	438	684	849	1553	
1966	21.60	12.00	577	756	832	1528	195
1967	22.90	12.14	829	740	802	1497	206
1968	23.69	12.60	1578	770	826	1583	204
1969	24.35	12.78	1137	782	888	1723	210
1970	26.62	14.33	714	728	873	1706	189
1971	27.63	15.83	642	746	864	1508	206
1972	27.53	16.94	1722	766	1006	1807	239

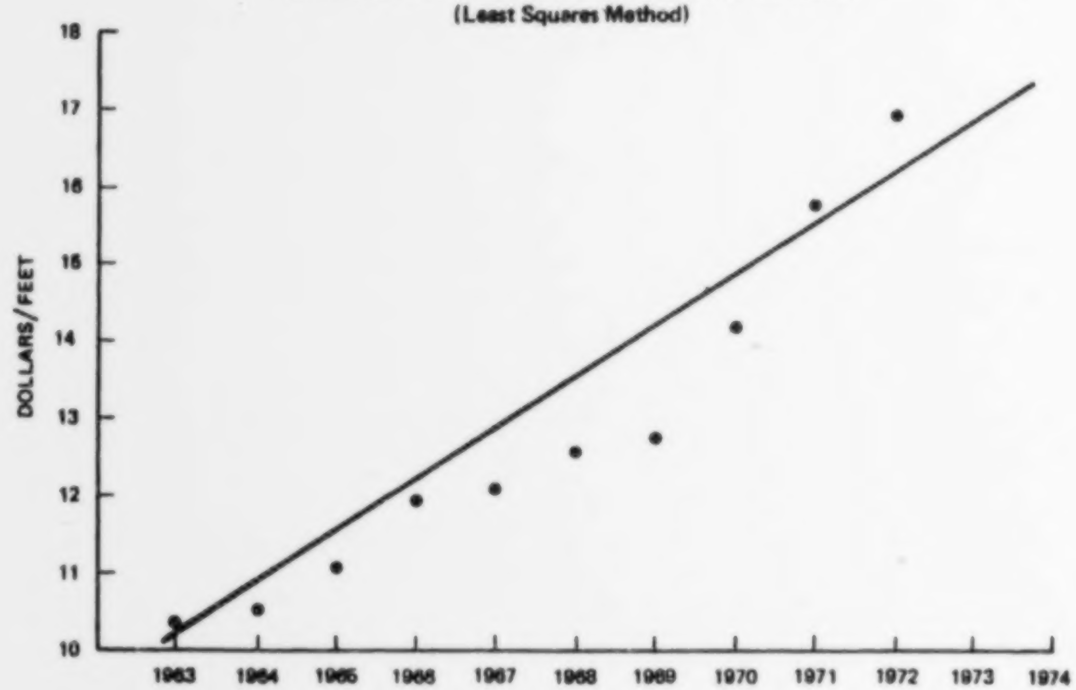
[2798]

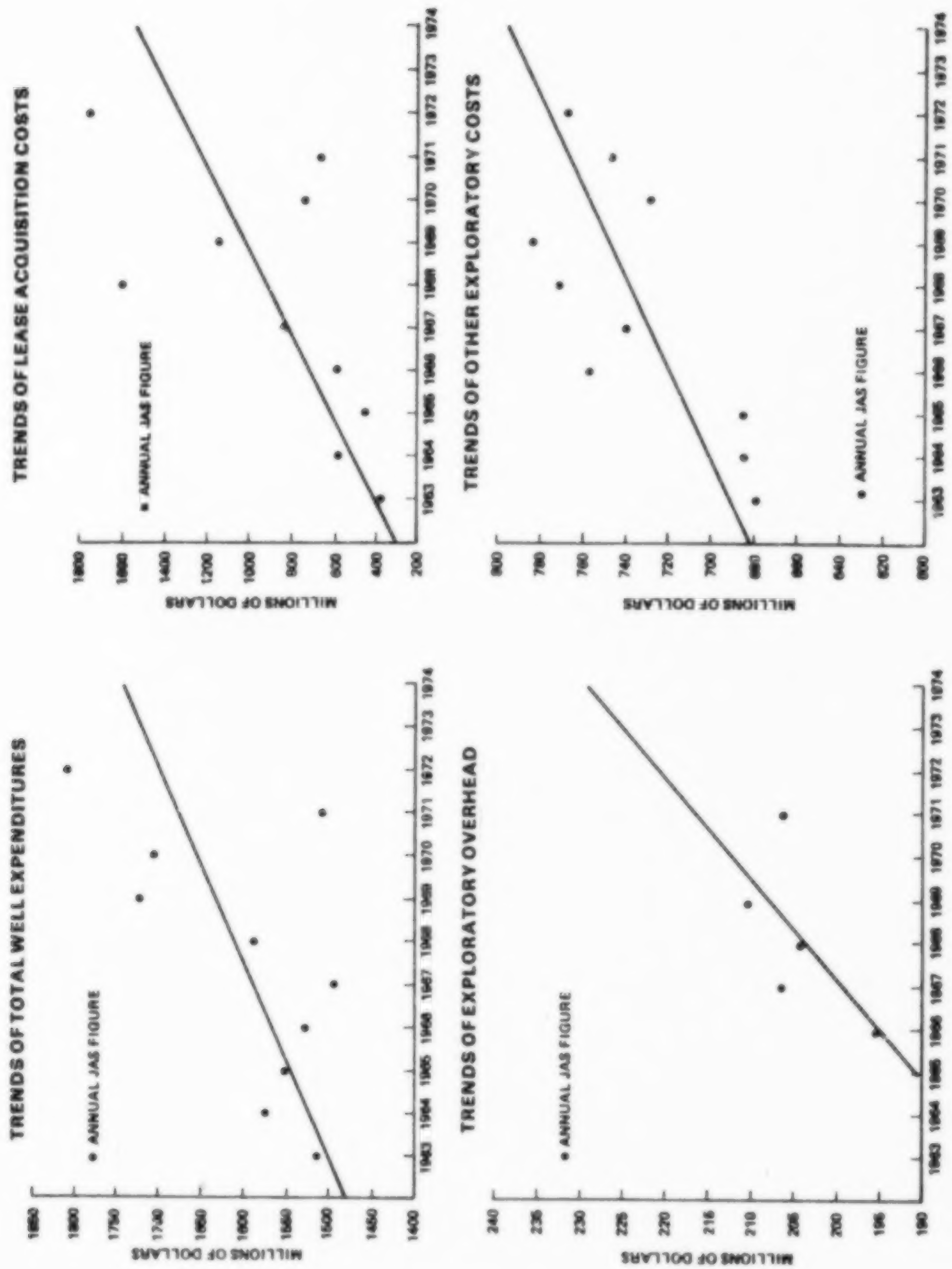
The trend in each series is unmistakable: Drilling costs are rising, as are indeed all cost components involved in our wellhead rate determinations. Statistical trending by the least squares regression technique reflects the following:

TREND OF SUCCESSFUL GAS WELL DRILLING COST PER FOOT
(Least Squares Method)



TREND OF DRY HOLE DRILLING COSTS PER FOOT
(Least Squares Method)





The upward trends in all costs are summarized in the exhibits attached to the testimony of George W. Kreig filed on May 7, 1974. These exhibits show the following:

Drilling Costs
1963 Through 1972

	Gas Well Cost		Dry Hole Cost	
Year	$ Per Foot	% Increase	$ Per Foot	% Increase
1963	17.11	-	10.42	-
1964	18.10	+ 5.8	10.54	+ 1.2
1965	18.16	+ 0.3	11.16	+ 5.9
1966	21.60	+18.9	12.00	+ 7.5
1967	22.90	+ 6.0	12.14	+ 1.2
1968	23.69	+ 3.4	12.60	+ 3.8
1969	24.35	+ 2.8	12.78	+ 1.4
1970	26.62	+ 9.3	14.33	+ 12.1
1971	27.63	+ 3.8	15.83	+ 10.5
1972	27.53	- 0.4	16.94	+ 7.0
Average Annual Increase		+ 5.4		+ 5.5

Exploration Costs and Overhead

	Geological, Geophysical And Other Exploratory		Exploration Overhead	
Year	Million $	% Increase	Million $	% Increase
1963	679	-	200	-
1964	685	0.9	215	7.5
1965	684	n	207	(3.7)
1966	756	10.5	195	(5.6)
1967	740	(2.1)	206	5.6
1968	770	4.1	204	(1.0)
1969	782	(1.6)	210	2.9
1970	728	6.9	189	(10.0)
1971	746	2.5	206	9.0
1972	766	2.7	239	16.0
Average Annual Increase		1.3		2.0

[2802]

Upon what rational basis can the ratemaking process ignore rising cost, declining productivity patterns when prospective rates are set. The question is rhetorical, for the answer clearly must be that rates based on fancy and not on fact cannot stand. It is a fact that costs are rising. It is a *fact* that productivity is declining. Only the majority's fancy lets them predict that 1973-1974 will violate the pattern of the recent past, and that productivity will increase while costs decrease.

I trust that a reviewing court will read the majority opinion with care to find why rising cost trends are ignored. It seems to me that the majority says only "we have always used averages; we think averages are reliable; we will use averages again". This, I submit, is not enough. We cannot lawfully claim expert judgment which flies in the face of the facts proved on the record.

If the 1973-1974 productivity range is assumed to be 340-420 Mcf/ft. (see pp. 5-10, *supra*), and costs are trended[6] rather than averaged over seven years, the cost estimate range for setting a prospective 1973-1974 rate becomes 58¢-71¢/Mcf. The calculations follow:

6. Trending follows the least squares regression technique, see pp. 16-18, *supra*.

[2803]

Trended Future Costs

	340 Mcf/ft. Unadjusted Productivity (AGA/AAPG)	420 Mcf/ft. Adjusted Productivity (AGA/AAPG)
1. Successful Well Costs	8.87	7.18
2. Recompletion	.20	.20
3. Lease Acquisition	7.46	6.04
4. Other Production Facilities	2.00	1.62
5. Subtotal	18.53	15.23
6. Dry Hole Expense	5.40	4.37
7. Other Exploration Expense	4.05	3.28
8. Exploration Overhead	1.23	1.00
9. Subtotal	10.68	8.65
10. Production Expense	3.10	3.10
11. Return @ 15%	29.18	23.99
12. Return on Working Capital	2.04	1.69
13. Liquid Credit	(3.89)	(3.89)
14. Regulatory Expense	.20	.20
15. Subtotal Before Royalty	59.84	48.97
16. Royalty	11.40	9.33
17. TOTAL	71.24	58.30

Trended	JAS Successful Well Costs (Dollars per Foot)	30.19
"	JAS Dry Hole Costs (Dollars per Foot)	17.03
"	JAS Lease Acquisition Costs (Millions of Dollars)	1,455
"	JAS Other Exploratory Expense (Millions of Dollars)	789
"	JAS Dry Hole Expense (Millions of Dollars)	941
"	JAS Cost of Producing Wells (Millions of Dollars)	1,730
"	JAS Exploratory Overhead (Millions of Dollars)	225

[2804]

B. *The Majority's Rate Determination Cannot Be Defended As a Whole.*

I have attempted to show that individual factual determinations essential to the majority's prescription of a 42¢/Mcf base rate as just and reasonable are wholly without evidentiary support. Let us now examine that rate as a whole, in order to gauge whether, despite infirmity in individual components, the rate can fairly be justified.

We have in this record actual costs for each of the four years 1969, 1970, 1971 and 1972. If we use the *Permian I* costing technique to reduce these costs to a cents-per-Mcf basis, we find:

1. Actual average costs in 1972 totaled	82.36¢/Mcf
2. Actual average costs in 1971 totaled	47.17¢/Mcf
3. Actual average costs in 1970 totaled	42.42¢/Mcf
4. Actual average costs in 1969 totaled	58.74¢/Mcf
5. The average cost during 1969-1972 totaled	55.24¢/Mcf

The majority is thus in the posture of saying that 1973-1974 costs will be less than the actual cost incurrence in any one of the last four years, and less than the average of the past four years. The majority is saying that they find that 1973-1974 costs may reasonably be expected to be roughly 50 percent of the actual costs experienced by the producers in 1972.

This simply cannot be true. There is no evidence in this record to support any rational belief that 1973-1974 costs will be lower than the most recent four years actual cost experience. Indeed there is no evidence to justify the conclusion that costs will remain at the same level as they have been. The only evidence before us says that 1973-1974 costs may reasonably be expected to rise above last year's level. As a whole, the majority's 42¢/Mcf rate determination is without evidentiary support.

I would emphasize that the actual cost experience for 1969 through 1972 is demonstrable from the record before us. Each figure necessary to calculation of *Permian I* costs is an

[2805]

actual cost figure; no judgment or discretion is involved in mechanically inserting actual figures into the formula.

The cost calculations for each year, and for the average of the four-year period, follow. In keeping with the earlier treatment of the productivity controversy with respect to AGA negative revisions to reserves and the 1.7 Tcf claimed disparity in reserve reporting, the calculations have been made alternately to reflect (1) actual figures as reported, and (2) reserve additions adjusted to totally eliminate all disputed items. When total acceptance of the attacks on the AGA data is indulged, *Permian I* costing still says that the majority's 42¢/Mcf rate is below actual costs in 1969 and in 1972, and below the average of actual costs experienced in 1969-1972. On the following pages, the column headed "Adjusted Productivity" reflects elimination of all negative revisions and addition of 1.7 Tcf for the years 1971 and 1972. The costing follows exactly the detail used by the majority in its Appendix C cost study.

[2806]

1972

		280 Mcf/ft. Unadjusted Productivity (AGA/AAPG)	390 Mcf/ft. Adjusted Productivity (AGA/AAPG)
1.	Successful Well Costs	9.83	7.06
2.	Recompletion	.20	.20
3.	Lease Acquisition	9.37	6.73
4.	Other Production Facilities	2.22	1.60
5.	Subtotal	21.62	15.59
6.	Dry Hole Expense	6.05	4.34
7.	Other Exploration Expense	4.17	2.99
8.	Exploration Overhead	1.38	.99
9.	Subtotal	11.60	8.32
10.	Production Expense	3.10	3.10
11.	Return @ 15%	34.05	24.55
12.	Return on Working Capital	2.50	1.82
13.	Liquid Credit	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20
15.	Subtotal Before Royalty	69.18	49.69
16.	Royalty	13.18	9.47
17.	TOTAL	82.36	59.16

Unadjusted Reserves Added (Bcf)	7,597
Adjusted Reserves Added (Bcf)	10,358
AAPG Footage Drilled (M Feet)	26,743
JAS Successful Well Costs (Dollars per Foot)	27.53
JAS Dry Hole Costs (Dollars per Foot)	16.94
JAS Lease Acquisition Costs (Millions of Dollars)	1,722
JAS Other Exploratory Expense (Millions of Dollars)	766
JAS Dry Hole Expense (Millions of Dollars)	1,006
JAS Cost of Producing Wells (Millions of Dollars)	1,807
JAS Exploratory Overhead (Millions of Dollars)	239

[2807]

1971

		380 Mcf/ft. Unadjusted Productivity (AGA/AAPG)	480 Mcf/ft. Adjusted Productivity (AGA/AAPG)
1.	Successful Well Costs	7.28	5.77
2.	Recompletion	.20	.20
3.	Lease Acquisition	3.10	2.46
4.	Other Production Facilities	1.65	1.30
5.	Subtotal	12.23	9.73
6.	Dry Hole Expense	4.17	3.30
7.	Other Exploration Expense	3.60	2.86
8.	Exploration Overhead	.99	.79
9.	Subtotal	8.76	6.95
10.	Production Expense	3.10	3.10
11.	Return @ 15%	19.26	15.32
12.	Return on Working Capital	1.00	.83
13.	Liquid Credit	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20
15.	Subtotal Before Royalty	40.66	32.14
16.	Royalty	6.51	5.16
17.	TOTAL	47.17	37.40

Unadjusted Reserves Added (Bcf)	8,565
Adjusted Reserves Added (Bcf)	10,887
AAPG Footage Drilled (M Feet)	22,609
JAS Successful Well Costs (Dollars per Foot)	27.68
JAS Dry Hole Costs (Dollars per Foot)	15.83
JAS Lease Acquisition Costs (Millions of Dollars)	642
JAS Other Exploratory Expense (Millions of Dollars)	746
JAS Dry Hole Expense (Millions of Dollars)	861
JAS Cost of Producing Wells (Millions of Dollars)	1,508
JAS Exploratory Overhead (Millions of Dollars)	206

[2808]

1970

		410 Mcf/ft. Unadjusted Productivity (AGA/AAPG)	420 Mcf/ft. Adjusted Productivity (AGA/AAPG)
1.	Successful Well Costs	6.50	6.34
2.	Recompletion	.20	.20
3.	Lease Acquisition	2.72	2.65
4.	Other Production Facilities	1.47	1.43
5.	Subtotal	10.89	10.62
6.	Dry Hole Expense	3.78	3.41
7.	Other Exploration Expense	2.77	2.70
8.	Exploration Overhead	.74	.72
9.	Subtotal	7.29	6.83
10.	Production Expense	3.10	3.10
11.	Return @ 15%	17.15	16.73
12.	Return on Working Capital	.89	.85
13.	Liquid Credit	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20
15.	Subtotal Before Royalty	35.63	34.44
16.	Royalty	6.79	6.56
17.	TOTAL	42.42	41.00

Unadjusted Reserves Added (Bcf)	9.351
Adjusted Reserves Added (Bcf)	9,641
AAPG Footage Drilled (M Feet)	22,852
JAS Successful Well Costs (Dollars per Foot)	26.62
JAS Dry Hole Costs (Dollars per Foot)	14.33
JAS Lease Acquisition Costs (Millions of Dollars)	714
JAS Other Exploratory Expense (Millions of Dollars)	728
JAS Dry Hole Expense (Millions of Dollars)	873
JAS Cost of Producing Wells (Millions of Dollars)	1,706
JAS Exploratory Overhead (Millions of Dollars)	189

[2809]

1969

		290 Mcf/ft. Unadjusted Productivity (AGA/AAPG)	350 Mcf/ft. Adjusted Productivity (AGA/AAPG)
1.	Successful Well Costs	8.00	6.96
2.	Recompletion	.20	.20
3.	Lease Acquisition	5.28	4.59
4.	Other Production Facilities	1.81	1.57
5.	Subtotal	15.29	13.32
6.	Dry Hole Expense	4.41	3.65
7.	Other Exploration Expense	3.63	3.16
8.	Exploration Overhead	1.01	.86
9.	Subtotal	9.05	7.67
10.	Production Expense	3.10	3.10
11.	Return @ 15%	24.08	20.98
12.	Return on Working Capital	1.51	1.32
13.	Liquid Credit	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20
15.	Subtotal Before Royalty	49.34	42.70
16.	Royalty	9.40	8.13
17.	TOTAL	58.74	50.83

Unadjusted Reserves Added (Bcf)	6,875
Adjusted Reserves Added (Bcf)	8,315
AAPG Footage Drilled (M Feet)	24,064
JAS Successful Well Costs (Dollars per Foot)	24.35
JAS Dry Hole Costs (Dollars per Foot)	12.78
JAS Lease Acquisition Costs (Millions of Dollars)	1,137
JAS Other Exploratory Expense (Millions of Dollars)	782
JAS Dry Hole Expense (Millions of Dollars)	888
JAS Cost of Producing Wells (Millions of Dollars)	1,723
JAS Exploratory Overhead (Millions of Dollars)	210

[2810]

Avg. 1969 - 1972

		340 Mcf/ft. Unadjusted Productivity (AGA/AAPG)	410 Mcf/ft. Adjusted Productivity (AGA/AAPG)
1.	Successful Well Costs	7.81	6.47
2.	Recompletion	.20	.20
3.	Lease Acquisition	4.88	4.04
4.	Other Production Facilities	1.77	1.46
5.	Subtotal	14.66	12.17
6.	Dry Hole Expense	4.40	3.65
7.	Other Exploration Expense	3.64	3.01
8.	Exploration Overhead	1.00	.83
9.	Subtotal	9.04	7.49
10.	Production Expense	3.10	3.10
11.	Return @ 15%	23.09	19.17
12.	Return on Working Capital	1.42	1.19
13.	Liquid Credit	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20
15.	Subtotal Before Royalty	47.62	39.43
16.	Royalty	7.62	7.51
17.	TOTAL	55.24	46.94

Unadjusted Reserves Added (Bcf)	32,388
Adjusted Reserves Added (Bcf)	39,201
AAPG Footage Drilled (M Feet)	96,268
JAS Successful Well Costs (Dollars per Foot) (4-yr. avg.)	26.55
JAS Dry Hole Costs (Dollars per Foot) (4-yr. avg.)	14.97
JAS Lease Acquisition Costs (Millions of Dollars)	4,215
JAS Other Exploratory Expense (Millions of Dollars)	3,140
JAS Dry Hole Expense (Millions of Dollars)	3,631
JAS Cost of Producing Wells (Millions of Dollars)	6,744
JAS Exploratory Overhead (Millions of Dollars)	844

[2811]

If there are those who ask why this dissent urges that the Commission majority has no discretionary power to utilize a set of seven-year averages as the basis for a rate determination, and seems to argue instead for use of a four-year average, let me offer this response. I think the Commission is free to use whatever formula or combination of formulas it chooses to prescribe rates, if the end result can be shown to be just and reasonable. If the majority here could demonstrate, from the record, that its seven-year averaging produces a realistic forecast of 1973-1974 costs, we would have a different ball game. But when use of a seven-year average produces a result totally at odds with the record, then it seems to me that the claim of discretion and expertise are forfeit.

I do not argue for use of a four-year average, save in the sense that such a formula would enjoy record support as the relevant time period over which to analyze costs and productivity. Certainly reasonable Commissioners may differ concerning use of any averaging technique, and I doubt that a four-year test period is any more, or any less, defensible than a three-year, or a two-year test period. I offer the results of four-year averaging only to demonstrate that the majority is wrong—that its cost predictions based on a remote test period seven years in length has no support in this record. As a matter of personal conviction I would discard averages altogether and employ trending to estimate future costs. This is the only hope for the Commission to avoid rates which are out-of-date before they become effective.

C. *The majority denies recovery of all producer-incurred costs.*

If, as now seems apparent, a majority of the Commission intends to adhere to rate-base, rate of return methods of prescribing wellhead rates, it is incumbent upon the Commission to do so fairly and honestly. A deliberate refusal to recognize a significant cost cannot be tolerated.

Such an omission exists in the majority opinion.

Income taxes are a legitimate component of a public utility's cost of service, *Galveston Electric Company* v.

[2812]

City of Galveston, 258 U.S. 388 (1922), and for rate-making purposes, income taxes are treated as costs incurred in the operation of the enterprise. *City of Chicago* v. *F.P.C.*, 458 F.2d 231 (D.C. Cir., 1971), cert. denied, 405 U.S. 1074 (1972).

A fundamental assumption of the entire area rate concept is that a rate may appropriately be determined with reference to the production and sale of a single Mcf of natural gas. This is accomplished by relating the total nationwide cost of the production to production in such a manner that each Mcf of gas produced and sold is deemed to bear its specific share of the costs incurred by producers. Moreover, the allowance of a return on investment is made by including an amount for such a return in the price of each Mcf of gas which is sold. It is in keeping with this underlying assumption that an allowance for federal income liability should be computed with reference to the tax liability which each individual Mcf of gas produced and sold would generate. If each Mcf generates taxable income (more revenue than cost)—and

this is the whole theory of *Permian* methodology—then the Commission may not lawfully deny that tax liability is created under the Internal Revenue Code.

The majority argues that only actual taxes paid by each producer should be allowed as a tax component. Application of *actual* taxes, to the average producer's *derived* costs renders the ratemaking concept meaningless. Moreover, the use of producers' filed tax returns to derive the tax component would be misleading. Filed returns reflect the the tax effects of extraneous and nonjurisdictional business operations.. Thus, actual returns are not only unnecessary they would be misleading for the reasons stated in the *Florida Gas* and *Naural Gas* cases *infra*.

From this record, it is clear that a producer who produced and sold an Mcf of natural gas at the costs indicated in the majority opinion would have taxable income on that sale. If a producer did not actually pay federal income tax for the year, it would be because (a) his deductible expenditures in the year exceed the revenues received for the gas, or (b) he had deductions attributable to nonjurisdictional activities.

[2813]

It would be illogical to reduce the allowance for federal income tax in computing the cost of gas which the producer sold in that year because the producer's expenditures were disproportionate to the volume of his gas sales for the year. If he is drilling for oil and gas, isn't this what the Commission wants, *Cf. F.P.C.* v. *Memphis Light, Gas & Water, Div.*, 93 S. Ct. 1723 (1973) where the Supreme Court allowed natural gas pipelines who use accelerated depreciation to normalize the benefits of deferred taxes.

A producer should currently deduct intangible drilling costs and dry hole expenses as incurred. A producer who produced a given quantity of gas and who currently deducted intangible drilling costs and dry hole expenses might, initially, incur net operating losses under Section 172 of the Internal Revenue Code of 1954, thus deferring paying tax. However, the overall production and sale of the gas in question over a period of years will generate aggregate federal income tax liability.

The Commission in Permian I acknowledged the principle of including an income tax component in cost of service as to producers of natural gas, but did not include it at that time because there was insufficient evidence to support it. (34 FPC at 206-7.)

This is no longer a justifiable basis for refusing to recognize a tax cost component, for since *Permian I* the Commission's policy has undergone a drastic change.

In *Florida Gas Transmission Co.,* 47 FPC 341, 362, rehearing denied, 49 FPC 261 (1973), appeal pending on other issues sub nom., *Sun Oil Co.* v. *F.P.C.,* D.C. Cir. Nos. 73-1203 and 73-1413 (filed February 27, 1973), the Commission stated:

> "[T]o reduce the rates of a regulated pipeline because of such affiliated exploration and development activities would be discouraging to the very enterprise we now want to encourage. Furthermore, there has been an increasing tendency for pipeline affiliates to diversify and to engage in activities completely unrelated to gas pipeline operations or the gas business at all, so that determining a tax

[2814]

> allowance for the pipelines' jurisdictional business on the basis of the activities of a far-flung conglomerate bears less and less relationship to the operations in which we are properly interested."

Only a few months ago in the *Natural Gas* case[7] the Commission reaffirmed its policy in *Florida Gas, supra,* stating:

> ". . . reducing the rate of a regulated pipeline because of exploration and development by an affiliated company would discourage the very enterprise which, in this time of limited natural gas supplies, we wish to encourage; therefore, the tax losses sustained by an affiliate should not be used to reduce the tax allowance of another affiliate."
> (Mimeo at 2.)

This change in rationale applies to producers with even greater force than it does to pipelines; tax deductions from unregulated and nonjurisdictional activities should not be used to reduce the tax liability incurred in the production and sale of an Mcf of gas. Consistent, nondiscriminatory application of the principle in *Florida Gas* and *Natural Gas, supra,* dictates that nationwide costs of finding and producing natural gas include the full tax attributable to the sale of natural gas without regard to other, nonregulated operations.

The D. C. Circuit has recognized that average producer rates are hypothetical as applied to individual producers. The recovery by an individual producer of an "average"

7. *Natural Gas Pipeline Co.,* Docket Nos. G-16026, *et al.,* Order issued September 17, 1973.

tax paid by the "average" producer has been upheld in *City of Chicago* v. *F.P.C., supra,* wherein the Court said that the tax element of the area rate should not be treated differently from other cost elements and therefore recovery by an individual producer of an "average" tax paid by the "average" producer is proper. *City of Chicago* v.*F.P.C., supra.* The Court stated:

[2815]

> "... When area rates are used, however, all elements of cost on which the rate is based are to some degree hypothetical, for they are derived from average costs incurred by producers within the relevent area. Regardless of the category of costs, some producers will actually spend less than is attributed to that category in the composition of the area rate. We conclude, therefore, that the tax element of the area rate should not be singled out for special treatment simply because area rates are applied to pipeline production." 458 F.2d at 731. (Footnotes omitted.)

The United States Supreme Court, the Circuit Courts, and the Commission have all determined that producer rates may appropriately be based on average costs and not individual cost of service. The D. C. Circuit has held that the recovery of taxes based on the average of tax liabilities is consistent with the area rate methodology and is, therefore, appropriate. The Commission has made crystal clear that the tax component of a rate is *not* to be computed by considering deductions from unrelated activities but should reflect the tax liability associated with the specific utility service, which in this case is the sale of natural gas. Consequently, the measure of taxes is *not* the actual tax paid by individual producers, which may

include taxes, deductions or credits attributable to unrelated activities. Nor is it the average of actual taxes of all producers, which would include taxes, deductions or credits attributable to unrelated activities. The tax component should, instead, be computed on the average nationwide new-gas cost.

The failure of the majority to include a known cost component in the rate set for new gas sales results in either confiscation or understatement of the return actually earned. Neither result can be defended. Inclusion of a cost component for income tax liability would result in an increase of at least 9¢/Mcf in the prescribed base rate[8], and the majority understates costs to this extent.

[2816]

Postscript—Part I—Costing Issues

The majority's estimated cost range of 37.54¢-42.7¢/Mcf for 1973-1974 gas production looks backward to outdated costs and outdated cost concepts. At a time when we simply cannot afford to repeat the error of understating costs and denying full cost recovery, the majority comes up with a rate which does both. That which permits the recovery of only a fraction of the costs reasonably to be anticipated in the next two years is not just and reasonable.

8. See Exhibit DWA-2, Producers May 7, 1974, filing; Response of Pennzoil, May 7, 1974. The exact amount of the tax cost component depends upon the revenue and expense assumptions inherent in the rate prescription formula.

II. Rate Base and Rate of Return—The Case of the Phantom Fifteen Percent

A. *Rate base issues.*

If, as now seems apparent, a majority of the Commission intends to adhere to rate-base, rate of return methods of prescribing wellhead rates, it is incumbent upon the Commission to do so fairly and honestly. A deliberate understatement of capital investment cannot be tolerated.

Such an understatement exists in the majority opinion.

When a producer first decides to drill a well, he does not know whether he will be successful or not. Nevertheless, he invests substantial sums of capital to drill with the hope and intent of finding a successful well. The commitment and the cost of the drilling investment is the same whether he is successful in finding gas or not. Yet, under the majority opinion, drilling costs associated with successful wells are treated differently than those associated with unsuccessful wells. The majority refuses to recognize that capital invested in dry holes must, legally, be compensated for to the same extent, and at the same rate, as capital invested in successful wells.

Proper cost based ratemaking must provide a return on all capital expenditures made for the convenience of the public. Under the majority opinion, the producer is allowed a return on the capital expenditures for four items:

[2817]

1. Successful Well Costs
2. Recompletions and Deeper Drilling

3. Lease Acquisitions
4. Other Production Facilities

The majority denies the capital nature of the following items by refusing to allow a return to be earned on them:

1. Dry Hole Expenses
2. Other Exploratory Costs

As Rodman points out:

> "Under Commission ratemaking practice, capital costs are 'capitalized' and depreciated and operating and maintenance costs are 'expensed.' The natural gas company recovers a portion of each type of cost in the price it receives for each Mcf of gas it sells. Whether depreciated or expensed, the recovery of Successful Well Costs and Dry Hole Costs remains the same, dollar for dollar. The difference is whether a return on capital expenditures is recognized as the cost of the capital required to finance the public service. Therefore, when calculating and allowing a return on Dry Hole Costs, the numbers in lines 6, 7 and 8 and 6-12 do not change, just as the numbers in Successful Well Costs, lines 1-4, do not change. The only thing that changes is the rate base on which return is allowed. The producer still recovers its investment in Successful Well Costs and Dry Hole Costs *exactly* the same whether or not a return is allowed on those costs. . . ." (Response, May 7, 1974.) (Footnote omitted.)

If no return on Dry Hole Costs is allowed, the producer never recovers the cost of the capital that went into that

investment; he is forced to donate the debt and equity cost of that investment free of charge.

When funds are committed to the search for and development of new gas supplies, it is not known, nor is it possible to know, which dollars of the total funds will be spent for wells which are commercially productive, and which dollars will be spent on dry holes. It is not possible to commit

[2818]

the funds required for the productive wells, and not commit the funds required for nonproductive wells. In order to obtain new gas supplies, a total investment expenditure must be made. If a return is allowed on only *part* of the funds that must be committed to gas supply ventures, decisions as to whether to venture new funds for new gas supplies will still be made based on the expected return on the total commitment; if the return on the total commitment is too low, it is not reasonable to expect that the funds will be ventured.

In rejecting capitalization of dry hole costs for rate-making purposes, the majority *does not* conclude that capital spent for dry hole costs is not an essential part of the business of providing gas service; nor does the majority deny that such expenditures are, in fact, made by producers as a continuing part of the business of providing gas service. Without a finding to the effect that dry hole expenditures are not essential, or that dry hole costs create nothing "used or useful" in the business, it is legally impermissible to force producers to donate their capital without recompense.

The majority rejects capitalization of dry holes because

this would "drastically reduce the risks involved in the exploration for and production of natural gas and place the Commission in the position of being a guarantor" (Opinion, p. 71). This is absolute poppycock. No producer gets one red cent by virtue of a Commission rate order unless he first takes the risk of drilling; a producer can spend $1 trillion on dry holes and recover none of it. The Commission guarantees nothing, except a ceiling rate if gas is found and sold interstate.

This record will not support denial of dry hole cost capitalization. The effect of denial is to deny at least 9¢-10¢/Mcf legally due and owing as a cost of invested capital.[9]

[2819]

B. *Rate of return issues.*

In arriving at rate of return, the majority compares apples and oranges and comes out with bananas. The majority says (p. 62):

> "We find no reliable evidence supporting a rate of return greater than 15 percent. This rate of return compares favorably with the returns earned by other extractive industries, utility companies, industrial concerns, and the overall earnings of large integrated producers and the predominately pure producer. These integrated oil and gas companies exhibit many

9. The majority's cost range is reflected in columns (b) and (g) of Appendix C, Schedule 1. If Dry Hole and Other Exploration Costs (lines 6 and 7) are included in rate base, the rate base becomes 17.38¢/Mcf in the high cost estimate and 15.30¢/Mcf in the low cost estimate. Return at 15 percent over a 10.5 year investment life should thus be increased 10.22¢/Mcf in the high cost estimate and 9.01¢/Mcf in the low cost estimate.

of the same characteristics of the pure producer and have many of the same risks. Thus, we find 15 percent to be a generous rate of return using comparable earnings as a guide. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 697 (1923); *FPC v. Hope Natural Gas Company,* 320 U.S. 591 (1944)."

If comparable earnings were truly our guide, we would forthrightly admit that the earnings of other enterprises that we look to are (a) *after-tax* earnings and (b) return on *total* capital invested. The 15 percent rate set by the majority generates *pre-tax* income, and is calculated on only *a portion* of invested capital.

As a consequence of understating costs, ignoring tax liability and understating the rate base, the majority does not, in fact, permit any producer to earn on a basis comparable with his other investment alternatives. The 15 percent magnanimously awarded by the majority is a phantom 15 percent—not realizable and not obtainable. I find the analysis of Dr. Ezra Solomon[10] to be unanswerable.

[2820]

Dr. Solomon testifies:

"The overall methodology used in order to translate the allowable rate into a price per MCF was wrong. In short, 12 percent or 15 percent applied to an estimated historical cost net book value 'rate-base' per MCF *plus* estimated expenses, depreciation, and taxes, *less* estimated credits for liquids did *not in fact* actually provide a yield of 12 percent or 15

10. Appendix A to May 7, 1974, filing of Producer Respondents.

percent on the new investment outlays required to find new supplies of gas.

There is a hugh [sic] volume of evidence—mathematical, economic and financial—which firmly indicates that [this] explanation provides a major reason for the consistent downward bias of regulatory prices."

* * *

"[Permian I] methodology contains three separate downward biases—each of which serves to translate any *intended* rate of return used in the calculations into a lower *actual* yield on investment outlays. The three built-in biases in the methodology are as follows:

1. Only part of investment is counted in the net investment rate base and a 'return' is provided only on that part so counted. The remainder of the investment is recouped through an annual allowance for expensed items and depreciation, but no effective return is allowed on this portion. As a result, the effective overall rate of return on *all* investments outlays required turns out to be much smaller than the apparent rate used in the calculations. This bias can and should be eliminated by applying the principles of 'full-cost' accounting to producer ratemaking.

[2821]

2. The methodology has based its cost estimates on *past,* sometimes remotely past, experience. The costs that are relevant for new investment deci-

sions are *future* expected costs. Past costs and trends in past costs are relevant only for the purpose of helping us make an estimate of probable future costs, but otherwise they play no part in the determination of the ceiling price for new gas.

3. If the methodology that has been used is amended to incorporate a 'full cost' rate base and the estimates themselves are based on *future* rather than historical data, it will get rid of two sources of downward bias that have afflicted ratemaking in the past. However, a third downward bias will still remain. This bias arises out of the basic mathematics of yield and rate of return, and is best explained by a simple numerical example:

(2) (sic) Assume that it takes an investment outlay of $1,000 to find and prove up 20 units of gas in 1974 which is to be withdrawn continuously at 1 unit a year starting on January 1, 1975.

(b) Assume that there are neither withdrawal costs, taxes, nor by-products.

(c) Assume that the required marginal or incremental rate of return or yield on a DCF basis for an investment of this riskiness is 15 percent per annum.

What price per unit of gas will provide a 15 percent yield?

The correct answer must be found in any one of the standard financial tables. It is $148.86 per unit.

The application of the same 15 percent rate within the net investment rate base methodology does not

give the same answer. Instead it would indicate a price of $125 per unit as follows:

[2822]

Average Net Investment Per Unit of Annual Production	$500
×	15%
Return Per Unit	$ 75
Depreciation Per Unit (Straight Line, 20 Years)	$ 50
Total Price Per Unit	$125

If *one-half* of the investment, i.e., $500, is 'expensed' because it is intangible, the downward bias of the Commission's old methodology increases. The price per unit required to produce a yield of 15 percent per annum on the investment is still of course $148.86. The price indicated by the Commission's methodology would be just $87.50 per unit, as follows:

Average Net Investment Per MCF	$250
×	15%
Return Per Unit	$ 37.50
Depreciation Per Unit (Straight Line, 20 Years)	25.00
Expensed Investment Per Unit	25.00
Total Price Per Unit	$ 87.50

Finally, if the methodology uses estimates based on past historical experience rather than future ex-

pected experience, the results are biased downward in yet another way. For example, historical finding cost might have been $800 to prove-up 20 units of gas although the expected 1974 cost is $1,000. The minimum

[2823]

price required for a 15 percent yield is still $148.86 per unit, i.e., at a lower price the investment would not be made. The Commission's methodology will indicate that the price required for a 15 percent return is $70 per unit or less than one-half the 'correct' answer.

A shift from conventional to full-cost accounting and a shift to *future* rather than historical cost estimations will remove two of the three biases but still leave the third downward bias. This last bias can be eliminated by abandoning the rate-base method in favor of a full DCF type calculation of the types put forward in the early area rate proceedings. If this is not done, it must be clearly recognized that the application of any given intended rate, e.g., 15 percent will in fact provide a significantly lower rate of return.

To summarize, a 15 percent rate of return on the $1,000 outlay it now takes to generate production of one unit of gas a year for 20 years must produce a cash flow of $148.86 a year. If the intended 15 percent rate is used in conjunction with the net investment rate base methodology it cannot produce the $148.86 which is required. A much higher 'rate' than the true intended rate must be used to arrive at the 'correct' price; how much higher depends on

the other aspects of the methodology, notably on conventional vs. full-cost accounting and on historical vs. near future cost estimates. In the simple example given above the 'applicable rate' which should be used in order to provide the intended $148.86 cash flow would be as follows:

(1) With 'full cost' accounting and 'future' cost estimates: 19.8 percent

(2) With 'conventional cost' accounting and 'future' cost estimates 39.5 percent

(3) With conventional cost accounting and cost estimates derived from historical data (generally the method used in previous area rate-making)—43.5 percent

[2824]

Those increasingly 'inflated' rates that must be applied to produce a yield of 15 percent bear little relationship to the intended rate itself. Because they are called 'rate of return' in the methodology itself there is little chance that any regulatory body will be able to use them in practice. Yet the brute fact in this industry is that unless such adjusted numbers are used in conjunction with the Commission's methodology the result will be a regulatory price that provides too low an effective rate of return to elicit the desired investment in new supplies.

It is a serious dilemma. It is one which must be faced squarely if the Commission now intends to correct the costly imbalance between growing unmet interstate demands and a vanishing interstate supply."

The clear import of this testimony to the legal sufficiency of the majority order is unmistakable. If a 15 percent rate of return is just and reasonable (Opinion, p. 61) and necessary to attract new capital to the business of gas exploration and development (Opinion, p. 64), and necessary to finance the degree of gas supply effort that is essential to the national well-being (Opinion, p. 64), and if the 42¢/Mcf rate will not generate a 15 percent rate of return, *ergo,* the 42¢ rate is not supportable.

This is precisely the point of witness Kreig's computer study attached to Mobil's Supplemental Comments filed May 29, 1974. Mr. Kreig analyzed a rate reflecting estimated costs of 42.74¢/Mcf (Revised Update High, Col. (f) in Revised Staff Study published March 21, 1974) and found that the true yield of such a rate is *7.6 percent,* before federal income tax. Our Staff performed a similar analysis, using different assumptions on investment and revenue timing, and concluded that a 42¢/Mcf rate generates a 12.6 percent true yield, before federal income tax. (See Appendix H to majority opinion.)

The majority order thus carries the seeds of its own self-destruction. A finding that a 15 percent rate of return is essential cannot be reconciled with a finding of a 42¢/Mcf rate which will not generate a 15 percent return.

[2825]

The issue here is not whether DCF costing should supplant rate-base, rate of return costing (although the former is clearly the more preferable), but rather, whether the majority's end result rate meets the internal criteria of justness and reasonableness of the rate of return agreed upon by the majority. If DCF analysis proves, as the

majority concedes, that the rate established herein will not produce a 15 percent rate of return, and the majority nonetheless chooses to adhere to a 42¢/Mcf rate determination, then it is demonstrated that the majority's exercise in "comparable earnings" analysis is a hoax.

[2826]

III. Of Noncost Factors: Where Did They Go?

The 42¢/Mcf rate found by the majority to be just and reasonable is based solely on the majority's estimation that 1973-1974 costs will fall in the range of 37.54¢-42.7¢/Mcf (Opinion, p. 96). A rate near the upper end of the cost range is selected, purportedly to fulfill an incentive function.

Turning aside for the moment from the fact that the estimated cost range does not represent the true range of costs reasonably to be expected in 1973-1974, I submit that the Commission is not legally free to base a wellhead rate of industry-wide applicability on the basis of costs alone.

The majority's misplaced reliance on costs alone is a giant step backward—back all the way to the very form of producer regulation most feared by Justice Jackson in his prophetic dissent in *Colorado Interstate,*[11] denounced by Judge Brown in *SoLa II,*[12] and most recently condemned by the Supreme Court.[13] The majority may not, lawfully, use costs as the "sole referential" in deciding a producer rate matter.

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11. *Colorado Interstate Gas Co. v. F.P.C.,* 324 U.S. 581 (1945).

12. *Placid Oil Co. v. F.P.C.,* 483 F.2d 880 (CA 5, 1973).

13. *Mobil Oil Corp. v. F.P.C.,* No. 73-437, Opinion issued June 10, 1974.

I perceive the law to be that the end result of our decision is more important than the formula used in arriving at a decision. I can read *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), no other way. I find no Supreme Court holding that producer costs are more significant than other considerations which bear upon consumer protection, nor do I find any Supreme Court mandate that our responsibilities begin, and end, with an examination of producer profit levels.

[2827]

To the contrary, decisions such as *F.P.C. v. Natural Gas Pipeline Co.*, 315 U.S. 575 (1942); *Wisconsin v. F.P.C.*, 373 U.S. 294 (1963); and *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968), teach that this Agency must be pragmatic, and flexible, in its rate decisions so that rates can be used functionally to achieve the full range of consumer protection—as to supply and price—entrusted to us.

Of all the decided cases, only *City of Detroit*[14] can be cited for the proposition that producer costs are controlling, and this holding has been repudiated in producer rate matters by *Phillips II*,[15] *Hugoton-Anadarko*[16] and *SoLa II*.[17] Decisions warning us not to equate "just and reasonable" with a mechanical approach to rate base and rate of return, and encouraging us to be flexible and pragmatic, are legion.[18]

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14. *City of Detroit v. F.P.C.*, 230 F.2d 810 (1955), cert. denied, 352 U.S. 829 (1956).

15. *Wisconsin v. F.P.C.*, 373 U.S. 249 (1963).

16. *California v. F.P.C.*, 466 F.2d 974 (CA 9, 1972).

17. *Placid Oil v. F.P.C., supra.*

18. See, *e.g.*, *F.P.C. v. Hope Natural Gas Co., supra; F.P.C. v.*

A contrary determination based on past court decisions such as *City of Detroit, supra* (which, it must be remembered, were rendered in times of plentiful supply) is, in these circumstances, tantamount to a statement by the Commission that the Natural Gas Act prevents the acquisition of new gas for the jurisdictional market in times of extraordinary market stress. This result is not contemplated by the Act nor is it required by any Court or Commission decision.

It is true that the courts have said that the price must be within the "zone of reasonableness." They have also said that one objective of the Natural Gas Act—as of public utility regulation in general—is to ensure adequate supply.

[2828]

Placid Oil Co. v. F.P.C., supra; Austral Oil Co. v. F.P.C., 428 F.2d 407 (5th Cir.) cert. denied 400 U.S. 950 (1970). Thus, while the Commission must consider costs, it need do so only as a point of departure, and not as the determinative factor.

The Supreme Court has repeatedly emphasized that the Commission's regulatory process cannot function properly if costs become our sole concern. In the *Permian Basin Area Rate Cases, supra*, the Court said:

> "[t]he Commission's responsibilities necessarily oblige it to give continuing attention to values that may be reflected only imperfectly by producers' costs; a regulatory method that excluded as immaterial all

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Natural Gas Pipeline Co., supra; Permian Basin Area Rate Cases, supra; Placid Oil Co. v. F.P.C., supra; City of Chicago v. F.P.C., 458 F.2d 731 (CADC 1971), cert. denied 405 U.S. 1074 (1972).

> but current or projected costs could not properly serve the consumer interests placed under the Commission's protection." 390 U.S. at 815.

The court has only recently reaffirmed this repudiation of regulation based on costs alone. See *Mobil v. F.P.C., supra,* at slip opinion pp. 21-22.

Notwithstanding a clear and unequivocal holding from the Supreme Court that "a regulatory method that excluded as immaterial all but current or projected costs could not properly serve the consumer interests," the majority now employs just such a regulatory method. Such critical noncost issues as capital requirements and intrastate rate levels, to mention only two of the many raised in the record before us, do not enter into the majority's rate determination. But if the rate we determine will not meet the capital needs attendant to expanded gas exploration and development, the rate we set is inadequate. And if our rate will not permit the successful competition by interstate pipelines for new onshore gas supplies, the rate we set is inadequate.

The majority's failure to look beyond current and projected costs in setting a rate will necessitate a remand by a reviewing court. An impermissibly narrow view of rate-making is presented.

[2829]

IV. *The End Result Test - A Failure of Federal Regulation*

In assailing the majority's rate determination of 42¢/Mcf as unjust and unreasonable, I willingly concede that it is the end result of the rate order which must withstand

judicial scrutiny,[19] and that a demonstration of internal flaws may not be sufficient to require reversal.[20]

In Part I of this dissent I sought to show that the end result of the majority opinion is to prevent producers from recovering costs reasonably to be anticipated; it is my belief that this defect, standing alone, is the type of unjustifiable end result which will necessitate judicial correction.

There is more which must be said, however, of the end result of the majority's order, for we have been consistently instructed by the courts that our producer rate orders must fulfill two separate functions: They must hold consumer costs to the lowest reasonable level, but they must also serve a supply eliciting function.[21] If the rate set permits a recovery of producer costs (including a fair return on investment) but is so low that it does not call forth an adequate and reliable supply of gas, the rate is not "just and reasonable" within the meaning of the Natural Gas Act.[22]

The majority's rate order fails to fulfill either the lowest reasonable cost function or the supply elicitation function which are both essential to the defense of the rate order as setting a just and reasonable rate. When, as here, a rate does not permit recovery of costs it is not just and reasonable; and, independently, when, as here, a rate does not permit movement of an adequate gas supply to interstate consumers, it is not just and reasonable.

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19. *F.P.C. v. Hope Natural Gas Co., supra.*

20. *Permian Basin Area Rate Cases, supra.*

21. *Austral Oil v. F.P.C., supra; Placid Oil v. F.P.C., supra; Permian Basin Area Rate Cases, supra.*

22. *Austral Oil Co. v. F.P.C., supra.*

[2830]

I wish to focus upon the end results of the majority order in the context of interstate gas supplies. The majority has not done so, nor have they acknowledged the bitter hardship which a 42¢/Mcf rate will force upon gas consumers served by interstate pipelines.

At the risk of being quite obvious, let me begin by observing that present and future gas supplies lie in two very different locations—in the offshore federal domain and in areas outside thereof. The offshore federal domain gas, present and future, by operation of law[23] is subject to the jurisdiction of this Commission. Any and all sales for resale (*e.g.* sales to pipelines) are sales in interstate commerce and therefore subject to rate regulation by this Commission. As to this gas, our rate orders have a dominant effect upon gas exploration and development in the true sense of economic incentives or disincentives.

Gas not within the offshore federal domain becomes subject to our rate jurisdiction only if the owner makes a sale in interstate commerce.[24] An onshore gas producer cannot be compelled to sell to the interstate market.[25] As to this gas, presently available for sale or which may become available for sale, our rate orders are no more than a tool in the hands of the gas buyers for interstate pipelines as they attempt to compete with intrastate pipelines and intrastate direct consumers for gas as it becomes

23. *Ship Shoal, Continental Oil Co. v. F.P.C.*, 370 F.2d 57 (CA 5, 1966), cert. denied 388 U.S. 910 (1967).

24. Section 1(b) Natural Gas Act, 15 U.S.C. §717, *et seq.*

25. *Permian Basin Area Rate Cases, supra.*

available. Onshore, and particularly in Texas, Oklahoma, and Louisiana, there are mature, fully developed, adequately financed intrastate buyers who can, by all present indications, absorb for intrastate consumption virtually all new gas supplies.

[2831]

It is my premise here that any rate order of this Commission which demonstrably cannot serve to (a) secure offshore gas supplies or (b) secure onshore gas supplies for interstate consumers fails the end result test of supply protection and is, by definition unjust and unreasonable. The majority rate orders bears such a stigma.

A. *Offshore Federal domain gas cannot be developed under the majority order.*

The pattern of recent bidding for Outer Continental Shelf leases reflects capital outlays by the industry of such magnitude that the majority's 42¢/Mcf rate will not cover the cash paid in lease acquisition costs and the cost of development. The majority's cost component for lease acquisition costs falls between 3.32¢ and 3.83¢/Mcf. (Opinion, pp. 79-80.)

In 1973 alone, industry spent over $3 billion in lease acquisition costs offshore. In the first quarter of 1974, $3.5 billion more has been invested in offshore lease acquisition. If we assume, conservatively, that one-third of the total bonus payments have been made for gas-prone acreage, then it follows that, as a rate of 3.83¢/Mcf, industry will have to find, and sell, over 50 Tcf of new gas to recover its 1973-1974 bonus payments, without regard to the time value of money which is recovered only over the productive life of the leases.

This is, of course, preposterous. This nation has never achieved 50 Tcf of new reserves from two years' offshore leasing, and there is no record evidence here to suggest that such might occur. To the contrary, the 1973 leases were estimated by USGS to cover, at most, 10.5 Tcf of natural gas.

This means, most simply, that if the USGS reserve estimates are reasonable, industry has obligated itself by cash outlay for lease acquisition costs of approximately 25¢/Mcf, ($2.5 billion ÷ 10.5 Tcf) without regard to the carrying cost on the investment. The majority order makes an allowance for lease acquisition costs that will not permit recovery of this investment. Offshore gas will not, in my judgment, be called forth under these circumstances.

[2832]

Of equal significance, the majority's prescription of a 42¢/Mcf base rate will preclude the issuance of new gas leases on the Outer Continental Shelf. The Department of the Interior, has in the two lease sales held in 1974, *refused to lease gas-prone tracts* to the highest bidder, where the bid did not comport with Interior's valuation of the potentially recoverable reserves. Interior is using a gas valuation of 45¢-75¢/Mcf in deciding whether to accept, or reject, the high bids.[26] This means, of course, that bids based on the majority's 42¢/Mcf ceiling will be rejected, unless Interior alters its leasing policies.

B. *Onshore gas will not be sold in interstate commerce under the majority order.*

Onshore new gas supplies are sold, all other things being equal in terms of pipeline access, to the highest bid-

26. Congressional Record, April 11, 1974, S.5835.

der. Under the majority's order, the interstate pipelines have a ceiling of 42¢/Mcf which can be paid as they compete with intrastate buyers. Can interstate gas buyers compete successfully under this arrangement? Not on your life.

The majority acknowledges that in April 1973 we were aware that intrastate prices were in the range of 40¢-50¢/Mcf (Opinion, p. 117.) The responses filed in May, 1974, reflect that intrastate prices reached 55¢-60¢ in the first half of 1973, 75¢-90¢ in the last half of 1973, and that current offers exceed $1.00/Mcf. (Shantz, pp. 12-14.) This evidence comports with that adduced in a recent series of cases wherein we sought to determine current intrastate price levels.[27] The evidence there, which included information concerning

[2833]

number of sales, volumes sold, and contract terms, demonstrates that interstate gas pipelines, armed with a 42¢ base rate maximum offer, will be effectively precluded from attaching new supplies.[28]

27. See, *e.g.*, *Apexco, Inc.*, Docket Nos. CI73-677, CI73-699 and CI73-804; *Brunson & McKnight*, Docket No. CI73-920; *Cities Service Oil Co.*, Docket No. CI74-49; *Gulf Oil Corp.*, Docket No. CI73-716; *Okmar Exploration*, Docket No. CI73-707; *C & K Petroleum, Inc.*, Docket No. CI73-697; and *Eason Oil Co.*, Docket No. CI73-644, all issued May 24, 1974; see also, *Egyptian Gas Storage*, Docket No. CI74-75, issued April 3, 1974.

28. As illustrative of the current level of intrastate prices, Exhibits offered and tested by cross-examination in Docket No. CI73-694, *Rodman Corporation*, show the following:

Exhibit 20 lists eleven recently-executed intrastate contracts and five which have been offered by the purchaser but not yet executed; none of the offered but not-yet-accepted contracts are below 55¢ base initial price, the others range from slightly below to substantially above 55¢.

The majority's failure to give consideration to the effect of their order on inter-intrastate gas supply competition is worse than merely erroneous—it is suicidal. Our refusal to permit the interstate market to compete with the intrastate market for new gas supplies can only operate to cripple the interstate market and enhance the gas procurement capability of the intrastate market. We cannot drive intrastate prices down by administrative fiat. The appetite of the natural gas-fueled industrial complex now in existence in the producing states is voracious, and current chronic energy

[2834]

shortages insure that more and more new supply increments will find a ready market without turning to interstate pipelines.

I would make it clear that I do not regard the intrastate market as an evil or destructive force. To the contrary, I regard the intrastate market as the logical economic answer to federal price regulation which denies that natural gas has an ascertainable market value. The intrastate market has grown because of, not in spite of, the FPC, and it has moved toward preeminence in the competition for new gas supplies because it is responsive to economic reality. Its operation is a constant check on the economic validity of federal regulation, and right now it is very

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Exhibit 22 lists twenty-one intrastate sales in the area ranging from 51.55¢ to 66.12¢; twelve of those prices exceed 55¢.

Exhibit 17 lists prices for Texas intrastate sales at or above 50¢ in May and June 1973, including prices of 70.1¢, 77.9¢, 77.9¢, 69.2¢, 59¢, 64.7¢ and 58.6¢. Those prices do not include any tax reimbursements which were paid by the buyers.

Exhibit 18 lists intrastate prices taken from recent testimony in Commission hearings, ranging up to 75¢ per Mcf and including prices of 60¢, 65¢, 70¢, 61¢ and 65.7¢.

easily demonstrating that market conditions are far more effective in calling forth new gas supplies than Federal Power Commissioners. The intrastate market is, and has been, of vital importance also in providing, where we have failed, the economic incentives necessary to stimulate gas exploration and development.

I do not, therefore, condemn the intrastate market. I accept it as a reality (which it is), and acknowledge that it will continue to exist (which it will). The failure of my colleagues to provide an effective procedure whereby interstate consumers can share in new gas discoveries makes inevitable the further deterioration of the interstate supply position.

[2835]

Conclusion

I confess my frustration with the outcome of R-389-B. A proceeding which began with great promise has come to naught. The order entered cannot withstand judicial scrutiny, but in the months that judicial review will consume, gas consumers are left with a national rate which will not materially alleviate the gas shortage. Deliverability will decline, curtailments will rise, economic disruption will ensue.

My dissent is to the 42¢/Mcf base rate prescribed by the majority.[29] I expressly concur in Part I—Procedural

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29. I deliberately refrain from expressing an opinion concerning the proper level of the base rate. My dissent goes to the legal sufficiency of the majority's rate determination, pointing out those instances in which costs have been understated or omitted, or other errors have been made in the application of *Permian I* costing. There is no reason for a dissent to do more. My individual conclusions on the justness and reasonableness of a rate order are immaterial to

Issues, Part II—Supply and Demand, Part IV—Environmental Impact, Part V—Deeper Drilling[30] and Offshore Water Depths. I concur with Part VI—Short-Term and Emergency Sales reluctantly; I concur because I feel we must secure long-term dedications to the interstate market, but do so reluctantly because of my previously expressed conviction that a 42¢/Mcf base rate will not permit successful onshore

[2836]

gas procurement by interstate pipelines. The balance is tipped in favor of elimination of short-term sales for the simple reason that we have already administratively destroyed the process through a series of recent decisions.[31]

I concur with so much of Part III—Rate Design as expands the applicability of the R-389-B rate to new sales and rededicated sales after expiration of an old contract. I concur in Part III's elimination of the "BTU gap" (see majority opinion, p. 102), and in the provisions for biennial review. I concur in the partial recision of existing moratoria, and I concur in the prescription of fixed annual escalations. I concur in the applicability of the R-

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Commission action, unless my conclusions coincide with those of at least two of my colleagues, and my individual views on the proper rate which should be set are equally immaterial to court review.

30. The Commission is indebted to GHK for its presentation in this proceeding, which was directed principally to the problem of deeper drilling. While we are unable to resolve this matter adequately at this time, I am sure that the entire Commission shares my recognition of the significant contribution of GHK to our understanding, and appreciation of the problem.

31. See Docket No. CI73-677, *Apexco, Inc.*, dissent issued May 24, 1974.

389-B rate to associated gas, in the treatment of small producers, and special relief proceedings.

The Federal Power Commission has within its grasp the last clear chance to fulfill its role in helping achieve the capability for domestic energy self-sufficiency. That last clear chance comes, and goes, with the ruling on motions for rehearing in this docket. I urge such motions for rehearing as all interested parties may choose to offer.

/s/ RUSH MOODY, JR.,
Rush Moody, Jr.,
Commissioner

[2837]

Just And Reasonable National	)	
Rates For Future Sales Of	)	Docket No.
Natural Gas From Wells Commenced	)	R-389-B
On Or After January 1, 1973	)	

SMITH, Commissioner, concurring:

The Commission seeks to achieve a regulatory process capable of flexible and timely response to the economic realities underlying the Nation's increasingly more desperate need for additional natural gas reserves. The Order issued today goes far toward establishing a procedure with a realistic capacity for reflecting the cost dynamics of finding and producing natural gas, and toward establishing a regulatory base whereby the regulated industry can make decisions with price certainty for the period covered by the Order and can make risk decisions for future activities with the expectation that rate reappraisals will be made that fairly credit the increasing costs that inevitably must be incurred. I concur in the issuance of the Order, but express the following reservations.

The decision that the R-389-B rate is applicable "to sales pursuant to contracts executed after January 1, 1973, where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after January 1, 1973," is inadquately supported, may be incompatible with our goal of securing long-term supplies for a long-range problem[1], and inhibits development of a methodology of adequately pricing new gas.

1. Termination of procedures allowing short-term sales to be effected is designed to achieve the supply and price security that can be achieved only by long-term dedications. However, implementation of this policy will be made more difficult by our decision that the biennial price review will allow gas under contracts expiring during each biennium to be eligible for the new gas price. Producer pressure for short contract terms to take advantage of future new-gas prices is inevitable.

The incremental price increase impact will be substantial.[2] That inflation has made serious inroads on the return from gas production is not a point of serious contention, nor is it questionable that relief for such costs should be granted upon proper consideration by this Commission. A great portion of the massive capital to support

[2838]

future exploration and development must be internally generated, and flowing gas price increments for this purpose should be determined. However, achieving these goals in the context of this proceeding is questionable, particularly when the price determined for gas from wells drilled after January 1, 1973, may be inadequate to encourage reinvestment of the funds so generated. But more pernicious is the inhibiting pall that increases in flowing gas prices casts over our appraisal of new gas costs, a legacy of the traditional misfit of utility costs concepts to wellhead gas pricing. It affects the manner in which we confront breakthrough points on new gas pric-

2. In Foster Associates, Inc., *The Impact of Deregulation On Natural Gas Prices, 1973*, Appendix A, Table 2-A, it is estimated that 1.63 Tcf of annual interstate sales are subject to contracts that will terminate between January 1, 1973, and January 1, 1980. That report further estimated that the average price for that gas under the existing area rates would be 23.5¢ per Mcf. Under this Order, that gas would be entitled to the rate of 42¢ plus annual 1¢ escalation for each year after 1973. Thus, by 1980 the annual revenue impact of including gas subject to terminating contracts will be at least $350 million, assuming that there is no increase in the base nationwide rate before 1980. The total revenue impact between now and 1980 will be in excess of $1 billion.

ing, such as reappraisal of the *Permian I* costing methodology in light of comments asserting that a discounted cash flow analysis (DCF) reveals that the rate of return deemed just and reasonable in actuality cannot be achieved by our methodology. (Order, p. 85.) We avoid reconciliation of our derived rate for new gas with the potentially meritorious DCF analysis in large part by pointing out that the ". . . Commission cannot set a price for new gas without also considering the cash flow consequences of its pricing policies for old gas." (Order, p. 87.) We divert the thrust of a proceeding designed to establish "rates high enough to provide the economic incentive for the unprecedented task of finding enormous volumes of new gas supplies. . ." (Order, p. 5,), by turning aside from the inquiry, justifying this by reference to judicial support of a rate structure evolved in *Southern Louisiana II*[3] wherein the Commission placed on flowing gas the charge of assuring cash flow for additional exploration. (Order, p. 87.)

[2839]

With no mechanism to monitor reinvestment of the price increase in gas subject to expired contracts, the expenditure of funds in the search for new gas for the interstate market will be made only if new gas rates fully cover costs and provide a reasonable return. To turn aside from pricing methodology reevaluation on the basis that deficiencies in the return on new gas can be made up for by increases in flowing gas rates can thwart the objective of both price increases. To balance the two and determine interdependent results may approximate

3. *Mobil Oil Corp. v. Federal Power Commission*, No. 73-437 (U.S. Supreme Court, June 10, 1974).

an overall industry-wide reasonable rate of return consistent with the utility pricing concept, but weakens the efficacy of this Order, and will inhibit the sorely needed new entries in the industry.

/s/ DON S. SMITH
Don S. Smith,
Commissioner

Docket No. R-389-B

APPENDIX A

American Gas Association *
Non-Associated Gas Reserves
MMCF @ 14.73 psia

United States (Excludes Alaskan Data)

Year	Revisions (a)	Extensions (b)	New Field (c)	New Reservoir (d)	Total 1/ (e)
1966	3,056,812	7,490,746	2,813,222	2,775,360	16,136,140
1967	3,712,892	8,625,273	2,819,635	2,126,298	17,284,098
1968	4,036,210	5,864,521	1,206,628	1,227,600	12,334,959
1969	(1,440,196)	4,788,627	1,663,266	1,863,021	6,874,718
1970	(290,034)	4,886,132	1,556,494	3,198,724	9,351,316
1971	(1,471,410)	5,625,841	1,176,939	3,234,033	8,565,403
1972	(1,911,097)	5,449,052	1,264,756	2,794,559	7,597,270

1/ These totals equal the summation of Columns (a) through (d). The parentheses () in Column (a) denote negative amounts.

*/ Reserves Of Crude Oil, Natural Gas Liquids, And Natural Gas In The United States And Canada And United States Productive Capacity As Of December 31, 1972, Volume 27, Published Jointly by the American Gas Association, American Petroleum Institute, and the Canadian Petroleum Institute (May 1973).

Docket No. R-389-B

DELIVERED FUEL COSTS TO STEAM ELECTRIC PLANTS BY REGIONS

First Quarter 1973

APPENDIX B
Sheet 1 of 2

Region	Coal (Sulphur Content) 1% or Less	1.01% to 3.0%	3.01% or More	Composite Weighted Average	Fuel Oil (Sulphur Content) No. 2 (Distillate)	.5% or Less	.51% to 2%	2.01% or More	Composite Weighted Average	Natural Gas (Cents Per Million Btu)
	------(Cents Per Million Btu)---------				------------(Cents Per Million Btu)--------------					
New England	71.93	48.86	1/	55.59	86.31	71.95	56.23	35.54	61.71	45.66
Middle Atlantic	51.47	42.68	39.09	43.32	92.27	74.61	56.97	43.98	68.81	49.90
E. N. Central	56.31	38.23	37.36	39.87	86.43	1/	67.37	80.80	72.70	58.25
W. N. Central	32.59	40.21	32.45	34.73	113.16	62.42	68.96	77.57	80.81	32.27
South Atlantic	44.94	42.58	35.82	42.12	92.57	71.13	61.19	45.52	55.88	42.65
E. S. Central	39.40	36.48	32.81	34.70	85.05	1/	74.91	69.62	74.62	38.63
W. S. Central	12.80	1/	1/	12.80	97.49	76.64	65.76	57.04	78.30	26.54
Mountain	24.08	1/	1/	24.08	95.55	100.17	77.10	68.03	87.21	37.03
Pacific	41.77	1/	1/	41.77	77.98	81.89	63.02	1/	81.75	40.67
Total U. S.	40.10	40.44	35.48	38.69	94.11	76.57	61.08	46.16	67.69	31.21

1/ No purchases.

Source: FPC, Bureau of Power, Monthly Report of Cost and Quality of Fuels for Steam-Electric Plants, September 1973. Report based on data collected in Form 423.

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Appendix B
Sheet 2 of 2

Prices of Gas and No. 2 Fuel Oil for Residential Heating in Representative Cities, 1970–73 1/
($ Per Million Btu)

Standard Metropolitan Statistical Areas	December 1970 Gas	December 1970 Fuel Oil	December 1971 Gas	December 1971 Fuel Oil	December 1972 Gas	December 1972 Fuel Oil	March 1973 Gas	March 1973 Fuel Oil	November 1973 Gas	November 1973 Fuel Oil
Atlanta	0.82	-	1.01	-	1.01	-	1.11	-	1.12	-
Baltimore	1.31	1.37	1.51	1.39	1.55	1.39	1.50	1.48	1.51	1.76
Boston	1.57	1.42	1.80	1.48	1.89	1.47	1.85	1.60	2.08	2.03
Buffalo	1.03	1.50	1.22	1.52	1.27	1.56	1.21	1.65	1.27	1.94
Chicago - N.W. Indiana	0.98	1.31	1.05	1.33	1.10	1.35	1.13	1.46	1.18	1.72
Cincinnati	0.81	-	0.92	-	0.98	-	0.95	-	0.95	-
Cleveland	0.85	-	0.88	-	0.94	-	0.94	-	0.92	-
Dallas	0.85	-	0.86	-	0.89	-	0.89	-	0.89	-
Detroit	0.87	1.34	0.94	1.34	0.99	1.35	1.00	1.48	1.16	1.68
Houston	0.93	-	0.93	-	0.99	-	1.01	-	1.03 2/	-
Kansas City	0.68	-	0.72	-	0.72	-	0.75	-	0.74	-
Milwaukee	1.26	1.38	1.35	1.36	1.39	1.37	1.39	1.47	1.40	1.84
Minneapolis - St. Paul	0.90	1.29	0.99	1.31	1.05	1.31	1.12	1.40	1.12	1.83
New York - N.E. New Jersey*	1.38	1.37	1.60	1.47	1.66*	1.47	1.67	1.57	1.89	2.14
Philadelphia	1.43	1.38	1.37	1.36	1.53	1.39	1.62	1.48	1.70	1.77
Pittsburgh	0.96	-	1.01	-	1.08	-	1.06	-	1.10	-
St. Louis	0.97	1.34	1.08	1.39	1.08	1.41	1.15	1.49	1.18	1.80
San Francisco - Oakland	0.70	-	0.76	-	0.77	-	0.84	-	0.89	-
Seattle	1.16	1.56	1.24	1.59	1.27	1.60	1.27	1.66	1.32	1.87
Washington, D. C.	1.35	1.38	1.50	1.42	1.57	1.43	1.55	1.54	1.60	1.89

*/ The burner tip price of $1.66 per million Btu in New York City in December 1972 is allocated as follows: 78 percent to the distributor, 12 percent to the pipeline company, and 10 percent to the producer.

1/ Prices include all applicable taxes. Gas price is based on average per therm above 40 therms per month. Fuel oil price is based on price paid for 100 gallons of No. 2 oil.

2/ Increase from shift to winter rates.
Source: Retail Prices and Indexes of Fuels and Electricity, 1973, Table 7, p. 6. (Bureau of Labor Statistics)

APPENDIX C
Schedule No. 1
Sheet 1 of 9

Docket No. R-389-B

Estimated Nationwide Cost of Finding and Producing Non-Associated Gas
(14.73 psia)
(Cents Per Mcf)

Line No.	Cost Component	Staff Low (a)	Staff High (b)	Update Low (c)	Update High (d)	Revised Update Low (e)	Revised Update High (f)	10 Year Estimate (g)	4 Year Estimate (h)
1.	Successful Wells	4.77	5.26	4.93	5.68	4.93	5.68	4.99	8.20
2.	Recomp. & Deeper Drilling	.20	.20	.20	.20	.20	.20	.20	.20
3.	Lease Acquisitions	2.92	3.21	3.32	3.83	3.32	3.83	3.36	5.13
4.	Other Production Facilities	1.08	1.19	1.11	1.28	1.11	1.28	1.13	1.85
5.	Subtotal	8.97	9.86	9.56	10.99	9.56	10.99	9.68	15.38
6.	Dry Holes	2.95	3.26	3.27	3.77	3.27	3.77	3.32	5.45
7.	Other Exploration	2.24	2.47	2.27	2.62	2.27	2.62	2.30	3.68
8.	Exploration Overhead	.66	.73	.71	.82	.71	.82	.72	1.16
9.	Subtotal	5.85	6.46	6.25	7.21	6.25	7.21	6.34	10.29
10.	Operating Expense	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.10
11.	Return @ 15% & 9 years	11.97	13.18	12.77	14.70				
11a.	Return @ 15% & 10½ years					14.90	17.15	15.09	24.07
12.	Return on Working Capital	.90	.98	1.00	1.14	1.00	1.14	1.01	1.51
13.	Net Liquid Credit	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20	.20	.20	.20	.20	.20	.20
15.	Subtotal	27.10	29.89	28.99	33.45	31.12	35.90	31.53	50.66
16.	Royalty @ 16%	5.16	5.69	5.52	6.37	5.93	6.84	6.01	9.65
17.	Total @ 14.73 psia	32.26	35.58	34.51	39.82	37.05	42.74	37.54	60.31

Note: Sheet No. 1-A gives a brief description of the various parameters used in these cost estimates. Sheets 2 through 9 of Schedule No. 1 and Schedule Nos. 2 and 3 reflect the cost computations and data sources of each of the above cost estimates.

[2844]

Appendix C
Schedule No. 1
Sheet 1-a of 9

Summary Description of the Cost
Estimates Shown on Schedule No. 1

Columns (a) and (b) - Staff's cost estimates attached to the Commission's Notice of Rulemaking in Docket No. R-389-B dated April 11, 1973. Reflects 580 productivity (low estimate) and 525 productivity (high estimate) and an investment life of 9 years including lag time. Includes data available through the year 1971.

Column (c) - Update of Staff's low cost estimate shown in Column (a) to include 1972 JAS cost data and a productivity of 559 which is an average of the 11 year, 16 year and 26 year periods ending with 1972. An investment life of 9 years including lag time is employed.

Column (d) - Update of Staff's high cost estimate shown in Column (b) to include 1972 JAS cost data and a productivity of 485 which is an average of the 7 year period ending 1972 using AAPG drilling data in contrast to Column (c) which employs World Oil Drilling data for the longer periods. An investment life of 9 years including lag time is employed.

Column (e) - Update of Staff's low cost estimate shown in Column (a) to include 1972 JAS cost data, a productivity of 559 and a revision in investment life including lag time to reflect a period of 10.5 years in lieu of 9 years.

Column (f) - Update of Staff's high cost estimate shown in Column (b) to include 1972 JAS cost data, a productivity of 485 and a revision in investment life including lag time to reflect a period of 10.5 years in lieu of 9 years.

Column (g) - Estimate of new gas cost using productivity of 552 which is the average for the 10 year period 1963 - 1972 and including 1972 JAS cost data. An investment life including lag time of 10.5 years is employed.

Column (h) - Estimate of new gas cost using a productivity of 336 which is the average for the 4 year period 1969 - 1972 and including 1972 JAS cost data and cost relationships for this period. An investment life including lag time of 10.5 years is employed.

[2845]

Appendix C
Schedule No. 1
Sheet 2 of 9

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (a) OF SHEET 1)

Line No.

1. 4.77=$27.64/ft. (1971, JAS)÷580 Mcf/ft. (Schedule No. 2)
2. .20=(Opinion No. 662)
3. 2.92=4.77 (Line 1)×.6112 (Schedule No. 3)
4. 1.08=4.77 (Line 1)×.226 (Opinion No. 598)
5. 8.97=Sum of Lines 1-4
6. 2.95=$15.83/ft. (1971, JAS) ×1.0×1.08÷580 Mcf/ft. (Schedule No. 2)
7. 2.24=2.92 (Line 3×.7686 (Schedule No. 3)
8. .66=[2.95 (Line 6)+2.24 (Line 7)]×.1266 (Schedule No. 3)
9. 5.85=Sum of Lines 6-8
10. 3.10=(Opinion No. 598)
11. 11.97=[8.97 (Line 5)—½×.20 (Line 2)]×9×.15 (Opinion No. 3)
12. 0.90=[5.85 (Line 9) ×⅛×1.336+3.10 (Line 10×⅛×1.689+2.92 (Line 3)×1.5]×.15 (Opinion No. 598)
13. (3.89)=(Opinion No. 598)
14. .20=(Opinion No. 598)
15. 27.10=Sum of Lines 1-14
16. 5.16=27.10 (Line 15)÷[1—.16]—27.10
17. 32.26=Sum of Lines 1-16

[2846]

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COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (b) OF SHEET 1)

Line No.

1. 5.26=$27.64/ft. (1971, JAS)÷525 Mcf/ft. (Schedule No. 2)
2. .20=(Opinion No. 662)
3. 3.21=5.26 (Line 1)×.6112 (Schedule No. 3)
4. 1.19=5.26 (Line 1)×.226 (Opinion No. 598)
5. 9.86=Sum of Lines 1-4
6. 3.26=$15.83/ft. (1971, JAS)×1.0×1.08÷525 Mcf/ft. (Schedule No. 2)
7. 2.47=3.21 (Line 3)×.7686 (Schedule No. 3)
8. .73=[3.26 (Line 6)+2.47 (Line 7)]×.1266 (Schedule No. 3)
9. 6.46=Sum of Lines 6-8
10. 3.10=(Opinion No. 598)
11. 13.18=[9.86 (Line 5)—½×.20 (Line 2)]×9×.15 (Opinion No. 598)
12. 0.98=[6.46 (Line 9)×⅛×1.336+3.10 (Line 10)×1.8×1.689+3.21 (Line 3)×1.5]×.15 (Opinion No. 598)
13. (3.89)=(Opinion No. 598)
14. .20=(Opinion No. 598)
15. 29.89=Sum of Lines 1-14
16. 5.69=29.89 (Line 15)÷[1—.16]—29.89
17. 35.58=Sum of Lines 1-16

[2847]

Appendix C
Schedule No. 1
Sheet 4 of 9

COST COMPUTATIONS (SOURCE)
REFER TO COLUMN (c) OF SHEET 1)

Line
No.

1. 4.93=27.53 (1972 JAS)÷559 Mcf/ft. (Schedule No. 2)
2. 0.20 (Opinion 662)
3. 3.32=4.93 (Line 1)×0.6741 (Schedule 3)
4. 1.11=4.93 (Line 1)×0.226 (Opinion 598)
5. 9.56=Sum of Line 1 - 4
6. 3.27=16.94 (1972 JAS)×1.08÷559 (Schedule No. 2)
7. 2.27=3.32 (Line 3)×0.6844 (Schedule 3)
8. 0.71=5.54 (Line 6+7)×0.1281 (Schedule 3)
9. 6.25=Sum of Lines 6 - 8
10. 3.10 (Opinion 598)
11. 12.77=[9.56 (Line 5)—½×0.20 (Line 2]×9×0.15 (Opinion 598)
12. 1.00=[6.25 (Line 9)×⅛×1.336+3.10 (Line 10)×⅛×1.689+3.32 (Line 3)×1.5]×0.15 (Opinion 598)
13. 3.89 (Opinion 598)
14. 0.20 (Opinion 598)
15. 28.99=Sum of Lines 1 - 14
16. 5.52=(28.99÷0.84)—28.99
17. 34.51=Sum of Lines 1 - 16

[2848]

Appendix C
Schedule No. 1
Sheet 5 of 9

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (d) OF SHEET 1)

Line
No.

1. 5.68=27.53 (1972 JAS)÷485 Mcf/ft. (Schedule No. 2)
2. 0.20 Opinion No. 662
3. 3.83=5.68 (Line 1)×0.6741 (Schedule 3)
4. 1.28=5.68 (Line 1)×0.226 (Opinion No. 598)
5. 10.99=Sum of Lines 1 - 4
6. 3.77=16.94 (1972 JAS)×1.08÷485 (Schedule No. 2)
7. 2.62=3.83 (Line 3)×0.6844 (Schedule 3)
8. 0.82=6.39 (Line 6+7)×0.1281 (Schedule 3)
9. 7.21=Sum of Lines 6 - 8
10. 3.10 (Opinion No. 598)
11. 14.70=[10.99 (Line 5)—½×0.20 (Line 2)]×9×0.15 (Opinion No. 598)
12. 1.14=[7.21 (Line 9)×⅛×1.336+3.10 (Line 10)×⅛×1.689+3.83 (Line 3)×1.5]×0.15 (Opinion No. 598)
13. 3.89 (Opinion No. 598)
14. 0.20 (Opinion No. 598)
15. 33.45=Sum of Lines 1 - 14
16. 6.37=(33.45÷0.84)—35.45
17. 39.82=Sum of Lines 1 - 16

[2849]

Appendix C
Schedule No. 1
Sheet 6 of 9

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (e) OF SHEET 1)

Line
No.

1. 4.93=27.53 (1972 JAS)÷559 Mcf/ft. (Schedule No. 2)
2. 0.20 (Opinion 662)
3. 3.32=4.93 (Line 1)×0.6741 (Schedule 3)
4. 1.11=4.93 (Line 1)×0.226 (Opinion 598)
5. 9.56=Sum of Lines 1 - 4
6. 3.27=16.94 (1972 JAS)×1.08—559 (Schedule No. 2)
7. 2.27=3.32 (Line 3)×0.6844 (Schedule 3)
8. 0.71=5.54 (Line 6+7)×0.1281 (Schedule 3)
9. 6.25=Sum of Lines 6 - 8
10. 3.10=(Opinion 598)
11. 14.90=[9.56 (Line 5)—½×0.20 (Line 2)]×10.5×0.15 (Opinion 598)
12. 1.00=[6.25 (Line 9)×⅛×1/336+3.10 (Line 10)×⅛×1.689+3.32 (Line 3)×1.5]×0.15 (Opinion 598)
13. 3.89 (Opinion 598)
14. 0.20 (Opinion 598)
15. 31.12=Sum of Lines 1 - 14
16. 5.93=(31.12÷0.84)—31.12
17. 37.05=Sum of Lines 1 - 16

[2850]

Appendix C
Schedule No. 1
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COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (f) OF SHEET 1)

Line
No.

1. 5.68=27.53 (1972 JAS)÷485 Mcf/ft. (Schedule No. 2)
2. 0.20 (Opinion 662)
3. 3.83=5.68 (Line 1)×0.6741 (Schedule 3)
4. 1.28=5.68 (Line 1)×0.226 (Opinion 598)
5. 10.99=Sum of Lines 1 - 4
6. 3.77=16.94 (1972 JAS)×1.08—485 (Schedule No. 2)
7. 2.62=3.83 (Line 3)×0.6844 (Schedule 3)
8. 0.82=6.39 (Line 6=7) 0.1281 (Schedule 3)
9. 7.21=Sum of Lines 6 - 8
10. 3.10 (Opinion 598)
11. 17.15=[10.99 (Line 5)—½×0.20 (Line 2)]×10.5×0.15 (Opinion 598)
12. 1.14=[7.21 (Line 9)×⅛×1.336+3.10 (Line 10)×⅛×1.689+3.83 (Line 3)×1.5]×0.15 (Opinion 598)
13. 3.89 (Opinion 598)
14. 0.20 (Opinion 598)
15. 35.90=Sum of Lines 1 - 14
16. 6.84=(35.90÷0.84)—35.90
17. 42.74=Sum of Lines 1 - 16

[2851]

Appendix C
Schedule No. 1
Sheet 8 of 9

COST COMPUTATION (SOURCE)
(REFER TO COLUMN (g) OF SHEET 1)

Line
No.

1. 4.99 = 27.53 (1972 JAS) ÷ 552 Mcf/ft. (Schedule No. 2)
2. 0.20 Opinion No. 662
3. 3.36 = 4.99 (Line 1) × 0.6741 (Schedule No. 3)
4. 1.13 = 4.99 (Line 1) × 0.226 (Opinion No. 598)
5. 9.68 = Sum of Line 1 - 4
6. 3.32 = 16.94 (1972 JAS) × 1.08 ÷ 552 (Schedule No. 2)
7. 2.30 = 3.36 (Line 3) × 0.6844 (Schedule 3)
8. 0.72 = 5.62 (Line 6 + 7) × 0.1281 (Schedule 3)
9. 6.34 = Sum of Lines 6 - 8
10. 3.19 Opinion No. 598
11. 15.09 = 9.68 (Line 5)—½ × 0.20 (Line 2) × 10.5 × 0.15
12. 1.01 = [6.34 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 3.36 (Line 3) × 1.5]
13. 3.89 Opinion No. 598
14. 0.20 Opinion No. 598
15. 31.53 = Sum of Lines 1 - 14
16. 6.01 = (31.53 ÷ 0.84)—31.53
17. 37.54 = Sum of Lines 1 - 16

[2852]

Appendix C
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Sheet 9 of 9

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (h) OF SHEET 1)

Line
No.

1. 8.20 = 27.53 (1972 JAS) ÷ 336 Mcf/ft. (Schedule No. 2)
2. 0.20 = Opinion No. 662
3. 5.13 = 8.20 (Line 1) × 0.6250 (Schedule 3)
4. 1.85 = 8.20 (Line 1) × 0.226 (Opinion No. 598)
5. 15.38 = Sum of Lines 1 - 4
6. 5.45 = 16.94 (1972 JAS) × 1.08 ÷ 336 (Schedule No. 2)
7. 3.68 = 5.13 (Line 3) × 0.7170 (Schedule 3)
8. 1.16 = 9.13 (Line 6 + 7) × 0.1269 (Schedule 3)
9. 10.29 = Sum of Lines 6 - 8
10. 3.10 Opinion No. 598
11. 24.07 = [15.38 (Line 5)—½ × 0.20 (Line 2)] × 10.5 × 0.15 (Opinion No. 598)
12. 1.51 = [10.29 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 5.13 (Line 3) × 1.5] × 0.15
13. 3.89 Opinion No. 598
14. 0.20 Opinion No. 598
15. 50.66 = Sum of Lines 1 - 14
16. 9.65 = (50.66 ÷ 0.84)—50.66
17. 60.31 = Sum of Lines 1 - 16

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APPENDIX C
Schedule 2
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NON-ASSOCIATED GAS RESERVE ADDITIONS AND
FOOTAGE DRILLED IN THE UNITED STATES
EXCLUDING ALASKA
(1947 - 1972)

Year	Estimated Reserves Added (BCF at 14.73 psi)	World Oil Successful Gas Well Footage Drilled (M Feet)	Joint Association Survey (M Feet)	American Association of Petroleum Geologists (M Feet)
1947	6,427	13,249		
1948	7,444	12,500		
1949	6,809	12,860		
1950	9,016	14,003		
1951	8,424	14,508		
1952	9,569	16,070		
1953	15,284	19,473		
1954	5,601	19,887		
1955	12,678	19,589		
1956	15,222	22,593		
1957	16,119	24,226		
1958	17,294	25,385		
1959	15,002	26,512	27,559	
1960	11,449	28,215	29,047	
1961	14,307	29,256	30,396	
1962	17,253	28,921	31,381	
1963	13,274	24,495	25,650	
1964	17,243	25,586	27,444	
1965	18,294	24,854	26,406	
1966	16,136	25,600	24,939	24,390
1967	17,283	21,440	21,708	20,789
1968	12,335	20,089	20,469	20,119
1969	6,875	21,645	23,543	24,064
1970	9,351	19,806	23,077	22,852
1971	8,565	20,042	22,107	22,609
1972	7,597	26,571	28,857	26,743

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NON-ASSOCIATED GAS RESERVES ADDITIONS
PER FOOT DRILLED IN WELLS PRODUCTIVE
OF GAS AND CONDENSATE
UNITED STATES EXCLUDING ALASKA
1947 - 1972

Year	AGA Estimated Reserves Added (Bcf at 14.73 psia)	World Oil Condensate and Gas Footage Drilled (M Feet)	Productivity (Mcf/ft.) (Col. 1 ÷ Col. 2)
1947	6,427	13,249	485
1948	7,444	12,500	596
1949	6,809	12,860	529
1950	9,016	14,003	644
1951	8,424	14,508	595
1952	9,569	16,070	595
1953	15,284	19,473	785
1954	5,601	19,887	282
1955	12,678	19,589	647
1956	15,222	22,593	674
1957	16,119	24,226	665
1958	17,294	25,385	681
1959	15,002	26,512	566
1960	11,449	28,215	406
1961	14,307	29,256	489
1962	17,253	28,921	597
1963	13,274	24,495	542
1964	17,243	25,586	674
1965	18,294	24,854	736
1966	16,136	25,600	630
1967	17,283	21,440	806
1968	12,335	20,089	614
1969	6,875	21,645	318
1970	9,351	19,806	472
1971	8,565	20,042	427
1972	7,597	26,571	286

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Appendix C
Schedule 2
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DERIVATION OF PRODUCTIVITIES

1. Productivity of 552, 559 and 580 Mcf per foot

United States Excluding Alaska

Time Period (a)	AGA Estimated Reserves Added (BCF at 14.73 psia) (b)	World Oil Footage Drilled (M Feet) (c)	Productivity (Mcf/ft.) (d)
1963-1972	126,953	230,128	552
1962-1972	144,206	259,049	557
1957-1972	218,377	392,643	556
1947-1972	314,851	557,375	565
1947-1971	307,254	530,804	579 1/

Average for 11, 16 and 26 year periods $\frac{(557 + 556 + 565)}{3}$ = 559

2. Productivity of 336, 485 and 525 Mcf per year

Time Period (a)	AGA Estimated Reserves Added (BCF at 14.73 psia) (b)	AAPG Footage Drilled (M Feet) (c)	Productivity (Mcf/ft.) (d)
1969-1972	32,388	96,268	336
1966-1972	78,142	161,566	484 2/
1966-1971	70,547	133,824	527 3/

1/ Rounded to 580.

2/ Rounded to 485.

3/ Rounded to 525.

Docket No. R-389-B

Appendix C
Schedule No. 3

Estimated Expenditures for Findings and Developing
Gas and Oil in the United States, 1967 - 1972
(Millions of Dollars)

Line No. (a)	Year (b)	Cost of Producing Wells (c)	Dry Hole Cost (d)	Lease Acquisition Cost (e)	Exploratory Overhead (f)	Other Exploratory Costs (g)
1.	1967	1497	802	829	206	740
2.	1968	1583	826	1578	204	770
3.	1969	1723	888	1137	210	782
4.	1970	1706	873	714	189	728
5.	1971	1508	864	642	206	746
6.	1972	1807	1006	1722	239	766
7.	1969-1972	6744	3631	4215	844	3022
8.	1967-1971	8017	4253	4900	1015	3766
9.	1967-1972	9824	5259	6622	1254	4532

10. Lease Acquisition Costs as a Fraction of Successful Well Cost = 6622 ÷ 9824 = 0.6741 (1967-1972); 4900 ÷ 8017 = 0.6112 (1967-1971); 4215 ÷ 6744 = 0.6250 (1969-1972)

11. Other Exploratory Costs as a Fraction of Lease Acquisition Costs = 4532 ÷ 6622 = 0.6844 (1967-1972); 3766 ÷ 4900 = 0.7686 (1967-1971); 3022 ÷ 4215 = 0.7170 (1969-1972)

12. Exploratory Overhead as a Fraction of Dry Hole and Other Exploratory Costs = 1254 ÷ 9791 = 0.1281 (1967-1972); 1015 ÷ 8019 = 0.1266 (1967-1971); 844 ÷ 6653 = 0.1269 (1969-1972)

Source: Joint Association Survey of the U. S. Oil & Gas Producing Industry, Section I and Section II.

Revised
Appendix C
Schedule No. 1
Sheet 1 of 7

Docket No. R-389-B

Estimate Nationwide Cost of Finding and Producing Non-Associated Gas 1/
(14.73 psia)
(Cents Per Mcf)

Line No.	Cost Component	Update Low (a)	Update High (b)	Revised Update Low (c)	Revised Update High (d)	10 Year Estimate (e)	4 Year Estimate (f)
1.	Successful Wells	4.88	5.57	4.88	5.57	4.92	7.78
2.	Recomp. & Deeper Drilling	.20	.20	.20	.20	.20	.20
3.	Lease Acquisitions	3.29	3.75	3.29	3.75	3.32	4.86
4.	Other Production Facilities	1.10	1.26	1.10	1.26	1.11	1.76
5.	Subtotal	9.47	10.78	9.47	10.78	9.55	14.60
6.	Dry Holes	3.24	3.70	3.24	3.70	3.27	5.17
7.	Other Exploration	2.25	2.57	2.25	2.57	2.27	3.48
8.	Exploration Overhead	.70	.80	.70	.80	.71	1.10
9.	Subtotal	6.19	7.07	6.19	7.07	6.25	9.75
10.	Operating Expense	3.10	3.10	3.10	3.10	3.10	3.10
11.	Return @ 15% & 9 years	12.65	14.42				
11a.	Return @ 15% & 10½ years			14.76	16.82	14.88	22.84
12.	Return on Working Capital	0.99	1.12	.99	1.12	1.00	1.44
13.	Net Liquid Credit	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20	.20	.20	.20	.20
15.	Subtotal	28.71	32.80	30.82	35.20	31.09	48.04
16.	Royalty @ 16%	5.47	6.25	5.87	6.70	5.92	9.15
17.	Total @ 14.73 psia	34.18	39.05	36.69	41.90	37.01	57.19

1/ Each cost study reflects an adjusted productivity to include an additional 1.7 Tcf of gas reserves for the years 1971-1972. Schedule No. 1-A gives a brief description of the various parameters used in these cost estimates. Sheets 2 through 7 of Schedule No. 1 and Schedule Nos. 2 and 3 reflect the cost computations and data sources of each of the above cost estimates.

[2858]

Revised
Appendix C
Schedule No. 1
Sheet 1a of 7

Summary Description of the Cost
Estimates Shown on Schedule No. 1.

General

Each of the productivities shown below are adjusted to include an additional 1.7 Tcf of gas reserves. The details are shown on Schedule 2, Sheet 1.

Column (a) - Update of Staff's initial low cost estimate to include 1972 JAS cost data and a productivity of 564 which is an average of the 11 year, 16 year and 26 year periods ending with 1972. An investment life of 9 years including lag time is employed.

Column (b) - Update Staff's initial high cost estimate to include 1972 JAS cost data and a productivity of 494 which is an average of the 7 year period ending 1972 using AAPG drilling data in contrast to Column (a) which employs World Oil Drilling data for the longer periods. An investment life of 9 years including lag time is employed.

Column (c) - Update of Staff's initial low cost estimate to include 1972 JAS cost data, a productivity of 564 and a revision in investment life including lag time to reflect a period of 10.5 years in lieu of 9 years.

Column (d) - Update of Staff's initial high cost estimate to include 1972 JAS cost data, a productivity of

494 and a revision in investment life including lag time to reflect a period of 10.5 years in lieu of 9 years.

Column (e) - Estimate of new gas cost using a productivity of 559 which is the average for the 10 year period 1963 - 1972 and including 1972 JAS cost data. An investment life including lag time of 10.5 years is employed.

Column (f) - Estimate of new gas cost using a productivity of 354 which is the average for the 4 year period 1969 - 1972 and including 1972 JAS cost data and cost relationships for this period. An investment life including lag time of 10.5 years is employed.

[2859]

Revised
Appendix C
Schedule No. 1
Sheet 2 of 7

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (a) OF SHEET 1)

Line
No.

1. 4.88=27.53 (1972 JAS) ÷ 564 Mcf/ft. (Schedule No. 2)
2. 0.20 (Opinion 662)
3. 3.29=4.88 (Line 1) × 0.6741 (Schedule 3)[1]
4. 1.10=4.88 (Line 1) × 0.226 (Opinion 598)
5. 9.47=Sum of Line 1 - 4
6. 3.24=16.94 (1972 JAS) × 1.08 ÷ 564 (Schedule No. 2)
7. 2.25=3.29 (Line 3) × 0.6844 (Schedule 3)[1]
8. 0.70=5.49 (Line 6+7) × 0.1281 (Schedule 3)[1]
9. 6.19=Sum of Lines 6 - 8
10. 3.10 (Opinion 598)
11. 12.65=[9.47 (Line 5)—½ × 0.20 (Line 2] × 9 × 0.15 (Opinion 598)
12. 0.99=[6.19 (Line 9) × ⅛ × 1.336+3.10 (Line 10) × ⅛ × 1.689+3.29 (Line 3) × 1.5] × 0.15 (Opinion 598)
13. 3.89 (Opinion 598)
14. 0.20 (Opinion 598)
15. 28.71=Sum of Lines 1 - 14
16. 5.47=(28.71 ÷ 0.84)—28.71
17. 34.18=Sum of Lines 1 - 16

1. *See* Appendix C.

[2860]

Revised
Appendix C
Schedule No. 1
Sheet *3* of *7*

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (b) OF SHEET 1)

Line
No.

1. 5.57 = 27.53 (1972 JAS) ÷ 494 Mcf/ft (Schedule No. 2)
2. 0.20 Opinion No. 662
3. 3.75 = 5.57 (Line 1) × 0.6741 (Schedule 3)[1]
4. 1.26 = 5.57 (Line 1) × 0.226 (Opinion No. 598)
5. 10.78 = Sum of Lines 1 - 4
6. 3.70 = 16.94 (1972 JAS) × 1.08 ÷ 494 (Schedule No. 2)
7. 2.57 = 3.75 (Line 3) × 0.6844 (Schedule 3)[1]
8. 0.80 = 6.27 (Line 6 + 7) × 0.1281 (Schedule 3)[1]
9. 7.07 = Sum of Lines 6 - 8
10. 3.10 (Opinion No. 598)
11. 14.42 = [10.78 (Line 5)—½ × 0.20 (Line 2)] × 9 × 0.15 (Opinion No. 598)
12. 1.12 = [7.07 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 3.75 (Line 3) × 1.5] × 0.15 (Opinion No. 598)
13. 3.89 (Opinion No. 598)
14. 0.20 (Opinion No. 598)
15. 32.80 = Sum of Lines 1 - 14
16. 6.25 = (32.80 ÷ 0.84)—32.80
17. 39.05 = Sum of Lines 1 - 16

1. *See* Appendix C.

[2861]

Revised
Appendix C
Schedule No. 1
Sheet *4* of *7*

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (c) OF SHEET 1)

Line
No.

1. 4.88 = 27.53 (1972 JAS) ÷ 564 Mcf/ft. (Schedule No. 2)
2. 0.20 (Opinion 662)
3. 3.29 = 4.88 (Line 1) × 0.6741 (Schedule 3)[1]
4. 1.10 = 4.88 (Line 1) × 0.226 (Opinion 598)
5. 9.47 = Sum of Lines 1 - 4
6. 3.24 = 16.94 (1972 JAS) × 1.08 ÷ 564 (Schedule No. 2)
7. 2.25 = 3.29 (Line 3) × 0.6844 (Schedule 3)[1]
8. 0.70 = 5.49 (Line 6 + 7) × 0.1281 (Schedule 3)[1]
9. 6.19 = Sum of Lines 6 - 8
10. 3.10 = (Opinion 598)
11. 14.76 = [9.47 (Line 5)—½ × 0.20 (Line 2)] × 10.5 × 0.15 (Opinion 598)
12. 0.99 = [6.19 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 3.29 (Line 3) × 1.5] × 0.15 (Opinion 598)
13. 3.89 (Opinion 598)
14. 0.20 (Opinion 598)
15. 30.82 = Sum of Lines 1 - 14
16. 5.87 = (30.82 ÷ 0.84)—30.82
17. 36.69 = Sum of Lines 1 - 16

1. *See* Appendix C.

[2862]

Revised
Appendix C
Schedule No. 1
Sheet *5* of *7*

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (d) OF SHEET 1)

Line No.

1. 5.57 = 27.53 (1972 JAS) ÷ 494 Mcf/ft. (Schedule No. 2)
2. 0.20 (Opinion 662)
3. 3.75 = 5.57 (Line 1) × 0.6741 (Schedule 3)[1]
4. 1.26 = 5.57 (Line 1) × 0.226 (Opinion 598)
5. 10.78 = Sum of Lines 1 - 4
6. 3.70 = 16.94 (1972 JAS) × 1.08 ÷ 494 (Schedule No. 2)
7. 2.57 = 3.75 (Line 3) × 0.6844 (Schedule 3)[1]
8. 0.80 = 6.27 (Line 6 + 7) 0.1281 (Schedule 3)[1]
9. 7.07 = Sum of Lines 6 - 8
10. 3.10 (Opinion 598)
11. 16.82 = [10.78 (Line 5)—½ × 0.20 (Line 2)] × 10.5 × 0.15 (Opinion 598)
12. 1.12 = [7.07 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 3.75 (Line 3) × 1.5] × 0.15 (Opinion 598)
13. 3.89 (Opinion 598)
14. 0.20 (Opinion 598)
15. 35.20 = Sum of Lines 1 - 14
16. 6.70 = (35.20 ÷ 0.84)—35.20
17. 41.90 = Sum of Lines 1 - 16

1. *See* Appendix C.

[2863]

Revised
Appendix C
Schedule No. 1
Sheet *6* of *7*

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (e) OF SHEET 1)

Line No.

1. 4.92 = 27.53 (1972 JAS) ÷ 559 Mcf/ft. (Schedule No. 2)
2. 0.20 Opinion No. 662
3. 3.32 = 4.92 (Line 1) × 0.6741 (Schedule No. 3)[1]
4. 1.11 = 4.92 (Line 1) × 0.226 (Opinion No. 598)
5. Sum of Lines 1 - 4
6. 3.27 = 16.94 (1972 JAS) × 1.08 ÷ 559 (Schedule No. 2)
7. 2.27 = 3.32 (Line 3) × 0.6844 (Schedule 3)[1]
8. 0.71 = 5.54 (Line 6 + 7) × 0.1281 (Schedule 3)[1]
9. 6.25 = Sum of Lines 6 - 8
10. 3.10 Opinion No. 598
11. 14.88 = [9.55 (Line 5)—½ × 0.20 (Line 2)] × 10.5 × 0.15
12. 1.00 = [6.25 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 3.32 (Line 3) × 1.5]
13. 3.89 (Opinion No. 598)
14. 0.20 (Opinion No. 598)
15. 31.09 = Sum of Lines 1 - 14
16. 5.92 = (31.09 ÷ 0.84)—31.09
17. 37.01 = Sum of Lines 1 - 16

1. *See* Appendix C.

[2864]

Revised
Appendix C
Schedule No. 1
Sheet 7 of 7

COST COMPUTATIONS (SOURCE)
(REFER TO COLUMN (f) OF SHEET 1)

Line No.

1. 7.78 = 27.53 (1972 JAS) ÷ 354 Mcf/ft. (Schedule No. 2)
2. 0.20 = Opinion No. 662
3. 4.86 = 7.78 (Line 1) × 0.6250 (Schedule 3)[1]
4. 1.76 = 7.78 (Line 1) × 0.226 (Opinion No. 598)
5. 14.60 = Sum of Lines 1 - 4
6. 5.17 = 16.94 (1972 JAS) × 1.08 ÷ 354 (Schedule No. 2)
7. 3.48 = 4.86 (Line 3) × 0.7170 (Schedule 3)[1]
8. 1.10 = 8.65 (Line 6+7) × 0.1269 (Schedule 3)[1]
9. 9.75 = Sum of Lines 6 - 8
10. 3.10 Opinion No. 598
11. 22.84 = [14.60 (Line 5)—½ × 0.20 (Line 2)] × 10.5 × 0.15 (Opinion No. 598)
12. 1.44 = [9.75 (Line 9) × ⅛ × 1.336 + 3.10 (Line 10) × ⅛ × 1.689 + 4.86 (Line 3) × 1.5] × 0.15
13. 3.89 Opinion No. 598
14. 0.20 Opinion No. 598
15. 48.04 = Sum of Lines 1 - 14
16. 9.15 = (48.04 ÷ 0.84)—48.04
17. 57.19 = Sum of Lines 1 - 16

1. *See* Appendix C.

[2865]

Revised
Appendix C
Schedule 2

DERIVATION OF PRODUCTIVITIES

1. Productivity of 559 and 564 Mcf per foot.

United States Excluding Alaska

Time Period (a)	AGA Estimated Reserves Added[1] (Bcf at 14.72 psia) (b)	World Oil Footage Drilled (M Feet) (c)	Productivity (Mcf/ft.) (d)
1963-1972	128,653	230,128	559
1962-1972	145,906	259,049	563
1957-1972	220,077	392,643	561
1947-1972	316,551	557,375	568

Average for 11, 16 and 26 year periods $\frac{(563+561+568)}{3}=564$

2. Productivity of 354 and 494 Mcf per year.

Time Period (a)	AGA Estimated Reserves Added[1] (Bcf at 14.73 psia) (b)	AAPG Footage Drilled (M Feet) (c)	Productivity (Mcf/ft.) (d)
1969-1972	34,088	96,268	354
1966-1972	79,842	161,566	494

[1] These totals have been increased by 1.7 Tcf for the years 1971 and 1972 to reflect the indicated disparity shown in Staff's report attached as Appendix B-1 to the Commission's Notice of March 21, 1974, in Docket No. R-389-B.

[2866]

Appendix D
Sheet 1 of 1

COMPUTATION OF EFFECTIVE NATIONAL RATE

Line No.	Rate Component	Cost (Cents Per Mcf)
1	Base National Rate	42.000
2	State Production Tax[1]	3.161
3	Subtotal	45.161
4	Btu Adjustment[2]	1.355
5	Subtotal	46.516
6	Gathering Allowance[3]	1.000
7	Offshore To Onshore Delivery[4]	1.000
8	Total	48.516

[1] A percentage production tax (assume 7 percent) is calculated as follows:
$[42.00 \div (1 - 0.07)] - 42.00 = 3.161$ cents/Mcf.
A flat rate production tax of 7 cents/Mcf is imposed by Louisiana.

[2] 1030 Btu per cubic foot assumed. Calculation is as follows:
$[(45.161)(1030 \div 1000)] - 45.161 = 1.355$ cents/Mcf.

[3] Gathering allowance is taken to be 1.0 cents per Mcf for illustrative purposes.

[4] Allowance for offshore to onshore delivery is shown. Note that only natural gas produced in offshore areas actually delivered onshore by producer's facilities qualifies for this adjustment.

[2867]

Appendix E

Selected Financial Data

Docket No. R-389-B

Sheet 1

Returns on Average Total Capital and Average Common Equity

1968 - 1972

Selected Aggregate Groups

1. Returns on Average Total Capital

Year	884 Industrials	508 Manuf. Cos.	S & P's 425 Industrials	125 Moody's Industrials	50 Largest Manuf. Cos.
1968	12.1%	11.6%	12.5%	11.4%	12.5%
1969	11.8	11.4	12.0	11.4	11.7
1970	10.5	10.2	11.1	10.7	10.7
1971	10.3	10.1	10.6	10.1	11.1
1972	11.0	10.9	11.4	10.8	12.0
Average	11.1%	10.8%	11.5%	10.9%	11.6%

2. Returns on Average Common Equity

Year	884 Industrials	508 Manuf Companies	S&P's 425 Industrials	Moody's 125 Industrials	50 Largest Manuf. Cos.
1968	14.6%	13.3%	14.8%	13.3%	15.1%
1969	13.9	12.9	14.1	12.9	14.4
1970	11.4	10.4	11.8	11.2	12.1
1971	11.0	10.3	11.2	10.8	12.8
1972	12.4	11.8	12.4	11.8	14.3
Average	12.7%	11.7%	12.9%	12.0%	13.7%

Source: Computed from data obtainable from Standard & Poor's.

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Sheet 2

Return on Total Capital and Common Equity
1972
By Industry Groups

Industry Group	Return on 1/ Total Capital	Return on 2/ Common Equity	
Aerospace	7.8	10.3	-1
Airlines	4.3	6.1	-2
Appliances	14.0	18.1	6
Automotive	14.2	16.7	-0-
Banks & Bank Holding Companies	10.4	12.5	8
Beverages	10.8	15.2	11
Building Materials	8.9	12.7	5
Chemicals	9.1	12.2	1
Conglomerates	7.9	13.9	8
Containers	8.1	10.9	7
Drugs	16.8	19.4	12
Electrical, Electronics	11.9	14.8	7
Food	10.7	13.5	6
General Machinery	NM	11.5	4
Instruments	16.0	17.3	11
Leisure Time Industries	9.4	13.6	16
Metals & Mining	6.1	7.7	4
Misc. Manufacturing	9.2	12.1	5
Office Equipment - Computers	13.1	15.3	13
Oil	8.6	11.1	5
Paper	7.4	9.7	2
Personal Care Products	17.7	20.4	10
Publishing	10.5	13.4	0
Radio & TV Broadcasting	12.7	19.4	6
Railraods	4.9	6.1	0
Retailing	10.2	12.4	NA
Savings & Loan	12.9	13.8	15
Service Industries	10.3	15.0	11
Specialty Machinery	12.4	14.8	5
Steel	5.5	6.4	-2
Textile & Apparel	7.4	8.7	3
Tire & Rubber	9.5	12.0	6
Tobacco	11.6	16.3	9
Trucking	14.0	20.8	14
Utilities (telephone, elec., gas)	6.8	10.8	4
Average	10.3	13.3	

1/ Footnotes are on the following page.

SOURCE: Business Week, May 12, 1973

Docket No. R-389-B Sheet 2a

FOOTNOTES:

1/ Return on Invested Capital. Ratio of net available for common stockholders - adjusted for preferred dividend requirements, minority interest, fixed charges - to total funds invested in company.

2/ Return on Common Equity. Ratio of net available for common stockholders to common equity, which includes common stock, capital surplus, retained earnings.

Sheet 3

Docket No. R-389-B

Capital Structure and Rates of Return
1972
Integrated Petroleum Companies

Company	C/E Ratio	Preferred Ratio	Debt Ratio	Return on Total Capital * 1971	Return on Total Capital * 1972	Return on * Net Worth 1971	Return on * Net Worth 1972
Atlantic Richfield	77.3%	-1.3%	21.4%	6.9%	6.4%	7.3%	6.5%
Cities Services	71.8	0	28.2	7.4	6.7	7.7	7.0
Continental Oil	68.3	1.8	29.9	8.3	9.2	9.1	10.4
Exxon Corporation	82.4	0	17.6	11.8	11.4	13.1	12.5
Gulf Oil	73.6	0	26.4	9.2	8.1	10.2	8.3
Ken McGee	76.2	4.2	19.6	8.5	9.1	10.7	10.0
Marathorn Oil	71.2	0	28.8	10.2	9.2	11.7	10.1
Mobil	82.6	0	17.4	10.2	10.2	11.2	11.2
Murphy Corp.	54.2	0.8	45.0	6.2	7.3	6.2	7.6
Phillips Petroleum	69.7	0	30.3	6.9	7.6	7.6	8.2
Shell Oil	74.0	0	26.0	8.0	8.1	8.7	8.9
Signal Co.	58.4	7.5	34.1	N.A.	N.A.	N.A.	N.A.
Pasco	39.8	0	60.2	N.A.	N.A.	N.A.	N.A.
Skelly Oil	88.9	0	11.1	6.9	6.6	7.0	6.7
Std. of Cal.	83.5	0	16.5	9.4	9.8	10.4	10.5
Std. of Ind.	78.2	0	21.8	8.8	8.9	9.6	9.9
Std. of Ohio	71.7	1.0	27.3	6.0	6.3	5.6	5.6
Texaco	84.1	0	15.9	12.1	11.3	13.4	12.4
Union Oil	68.7	4.8	26.5	7.1	7.3	7.4	7.6
Average	72.4	1.1	26.4	8.5	8.4	9.2	9.0

* End of period capital

SOURCE: Value Line

Docket No. R-389-B

RETURN OF TOTAL CAPITAL - PETROLEUM INDUSTRY

Sheet 4

1939 - 1972

Year	Number of Companies	Return on Average Total Capital	Return on Average Invested Capital 1/
1972	30	9.4	9.7%
1971	30.	10.1	10.7
1970	28	9.9	10.4
1969	N.A.	N.A.	11.0
1968	28	11.2	11.7R
1967	29	11.3	12.3
1966	29	11.4	12.1
1965	29	10.7	1.6
1964	31	10.3	11.1
1963	32	10.4	11.2
1962	33	9.6	10.3
1961	33	9.3	10.0
1960	32	9.2	10.0
1959	32	8.9	9.7
1958	32	8.7	9.5
1957	33	11.7	13.0
1956	33	12.4	13.9
1955	34	12.2	13.5
1954	35	11.6	13.0
1953	35	12.3	14.0
1952	30	12.3	14.0
1951	30	14.0	15.9
1950	30	12.7	14.6
1949	30	11.2	12.9
1948	30	16.9	20.0
1947	30	13.2	14.9
1946	30	9.3	10.3
1945	30	7.9	8.6
1944	30	8.7	9.6
1943	30	7.3	8.0
1942	3.0	6.0	6.6
1941	30	7.9	8.8
1940	30	5.9	6.3
1939	30	5.1	5.4

R - Revised

SOURCE: Financial Analysis of a Group of Petroleum Companies 1972, Chase Manhattan Bank.

Docket No. R-389-B

Sheet 4a

FOOTNOTE:

1/ Earnings represent net income; capital includes preferred stock, common stock and surplus.

Docket No. R-389-B

Sheet 5

Capitalization and Rates of Returns
Petroleum Industry
1972

	CAPITAL STRUCTURE			RETURN ON 2/	
	Debt	Equity	Other 1/	Total Capital	Net Worth
Pennzoil Co.	55.6%	35.7%	8.7%	8.3	14.2
Apco Oil Corp.	44.0	54.9	1.1	7.4	7.7
Amerada-Hess Corp.	44.1	55.2	.7	7.3	8.3
Ashland Oil, Inc.	36.1	53.4	10.5	10.6	13.4
Atlantic Richfield Co.	21.4	77.3	1.3	6.4	6.5
Belco Petroleum Corp.	40.3	59.7	-	8.2	9.6
British Petroleum Co.	37.1	59.8	3.1	5.3	4.7
Cities Service	27.9	69.3	2.8	6.7	7.0
Clark Oil and Refining	34.7	61.0	4.3	9.4	10.0
Commonwealth Oil	44.2	46.8	9.0	3.6	1.8
Continental Oil	28.6	66.7	4.7	9.2	10.4
Exxon Corp.	17.0	79.6	3.4	11.4	12.5
Gen. Am. Oil of Texas	.5	99.5	-	7.0	7.0
Getty Oil Co.	6.3	80.5	13.2	5.2	5.2
Gulf Oil Corp.	25.5	71.2	3.3	8.1	8.3
Gulf Oil Canada	18.7	70.8	10.5	8.6	8.8
Helmerich and Payne	48.0	52.0	-	8.8	12.0
Imperial Oil, Ltd.	14.6	74.1	11.3	12.4	13.5
Kerr-McGee Corp.	18.5	71.5	10.0	9.1	10.0
Louisiana Land and Expl.	30.5	69.5	-	20.5	28.9
Marathon Oil Co.	28.8	71.2	-	9.2	10.1
Mesa Petroleum	58.5	41.1	.4	11.5	26.2
Mobil Oil Corp.	16.8	79.9	3.3	10.2	11.2
Murphy Oil Corp.	35.0	42.1	22.9	7.3	7.6
Occidental Petroleum	54.0	44.7	1.3	4.8	2.4
Pacific Petroleums Ltd.	32.4	67.6	-	7.9	9.0
Phillips Petroleum Co.	29.6	68.0	2.4	7.6	8.2
Quaker State Oil	25.4	68.4	6.2	14.5	17.1
Royal Dutch Petroleum	20.4	68.6	11.0	7.2	7.2
Shell Oil Co.	26.0	74.0	-	8.1	8.9
Shell Transport and Trad.	21.8	66.4	11.8	7.2	7.2
Skelly Oil Co.	11.1	88.9	-	6.6	6.7
Standard Oil (Calif.)	16.5	83.5	-	9.8	10.5
Standard Oil (Ind.)	20.7	73.9	5.4	8.9	9.9
Standard Oil (Ohio)	26.9	68.8	4.3	6.3	5.6
Sun Oil Co.	22.8	69.8	7.4	8.4	8.9
Superior Oil Co.	22.3	77.7	-	2.5	1.5
Tesoro Petroleum	24.8	71.7	3.5	11.8	13.9
Texaco, Inc.	13.9	73.2	12.9	11.3	12.4
Union Oil of Calif.	26.3	68.2	5.5	7.3	7.6
United Refining Co.	36.9	63.1	-	11.6	14.0
Average	28.4	66.8	6.5	8.6%	9.9%

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FOOTNOTES:

Sheet 5a

1/ Note: Other includes: Preferred Stock, Deferred Taxes and Minority Interest.

2/ Returns are computed on End-of-period capital.

SOURCE: Value Line

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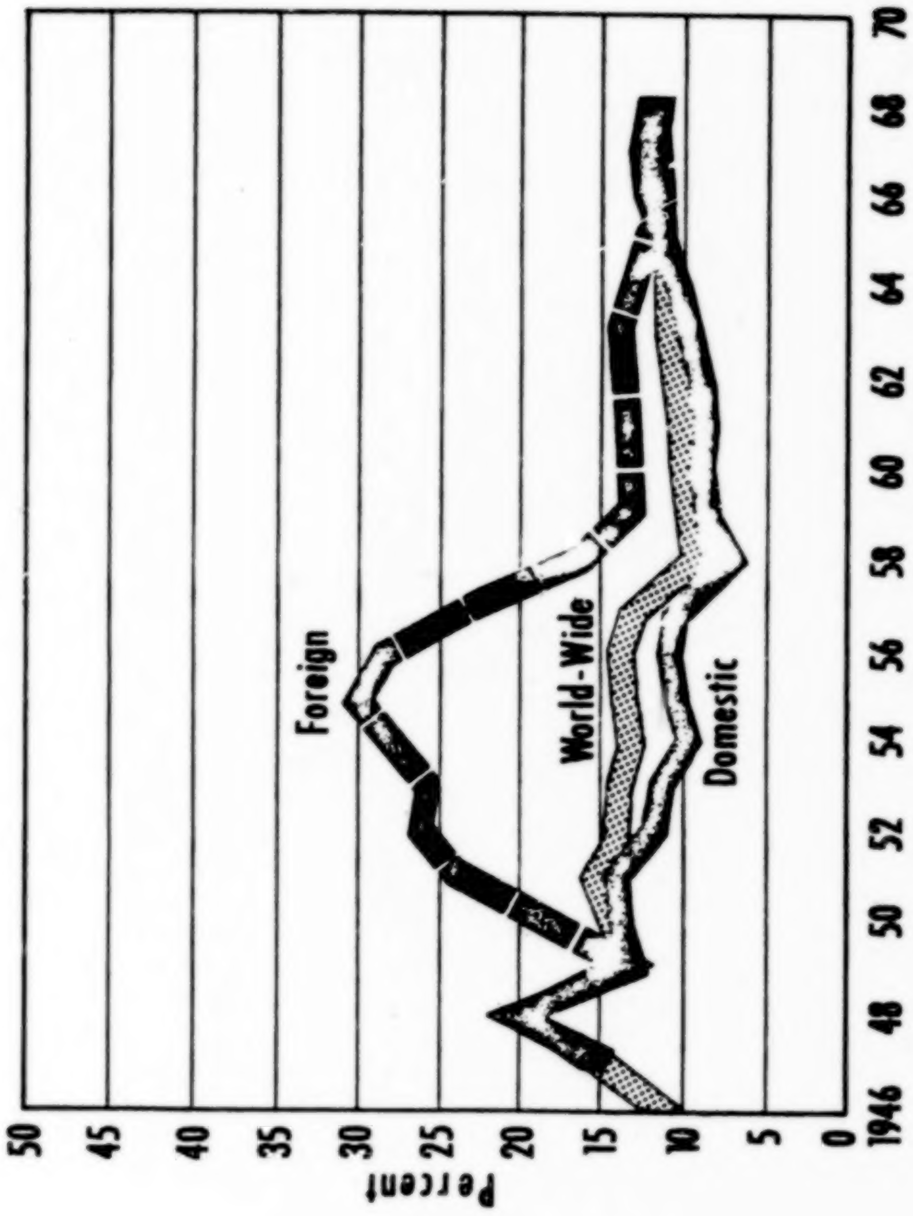
Sheet 6

RETURN ON EQUITY CAPITAL OF PETROLEUM COMPANIES, ANALYSIS BY CHASE MANHATTAN BANK
1946-1968

RETURN ON AVERAGE INVESTED CAPITOL 1/



1/ The Chase Manhattan Bank defines invested capital as including preferred stock, common stock and surplus.

Source: Annual Financial Analysis of a Group of Petroleum Companies, 1968

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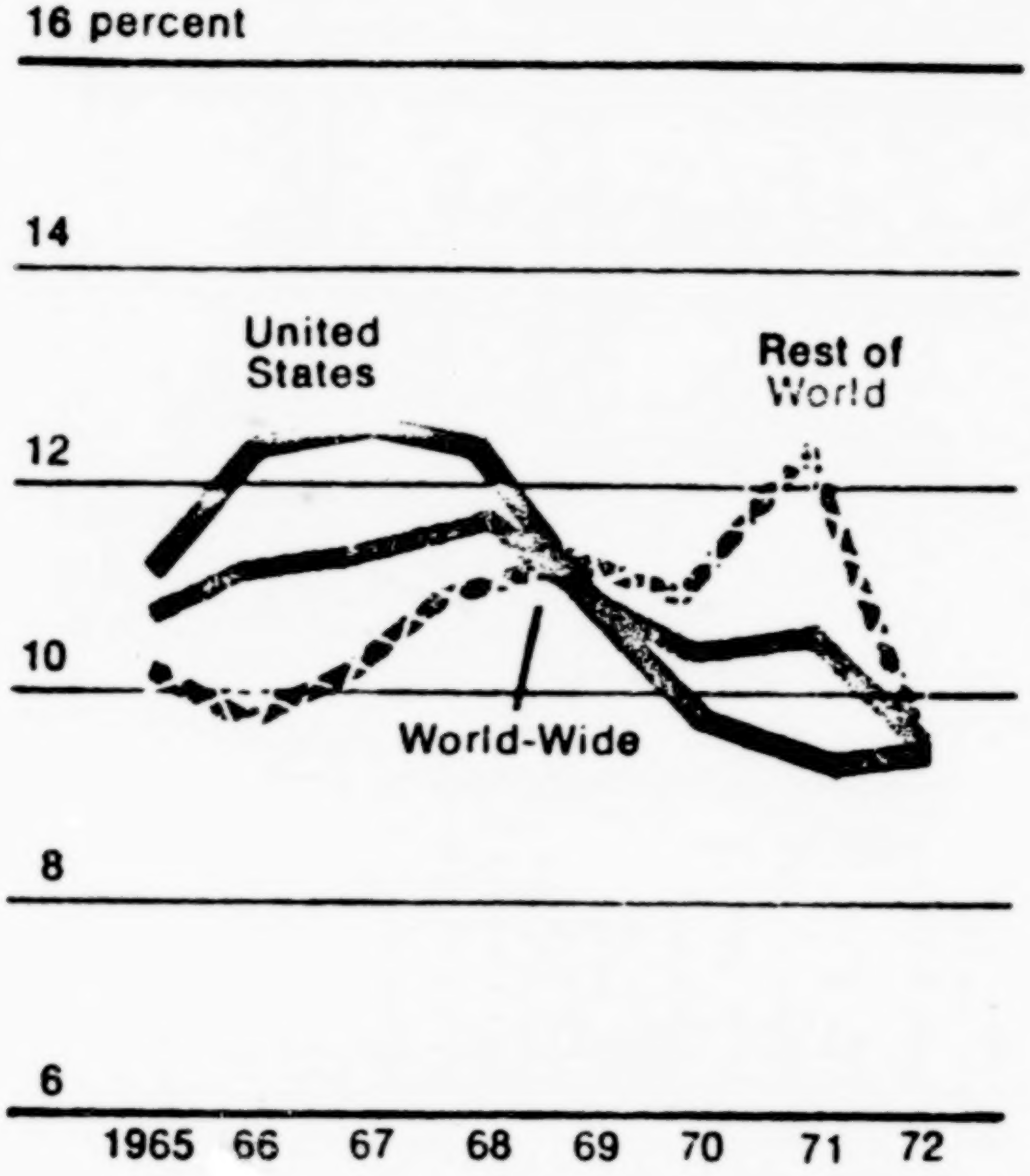
Sheet 7

RETURN ON AVERAGE INVESTED CAPITAL



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APPENDIX F

PRODUCTION CURVES

	Percent Of Contract Volumes Delivered Annually	
	CASE I	CASE II
Year	Constant Flow	Typical Flow 37 Year Reservoir Life 1/
1	5.56	2.03
2	5.56	3.95
3	5.56	5.23
4	5.56	6.08
5	5.56	6.60
6	5.56	6.60
7	5.56	6.60
8	5.56	6.60
9	5.56	6.60
10	5.56	6.60
11	5.56	6.60
12	5.56	6.60
13	5.56	6.08
14	5.56	5.54
15	5.56	5.12
16	5.56	4.69
17	5.56	4.27
18	5.56	3.84
	100.0	100.0
Constant Price Equivalent (cents per Mcf)	47.0	47.7

1/ This production curve is taken from Appendix D to the "Initial Decision Of The Presiding Examiner On Hugoton-Anadarko Area Rates," Area Rate Proceeding, et al. (Hugoton-Anadarko Area), 44 F.P.C. 824, 991 (1970).

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Appendix G
Sheet 1 of 2

Aggregate Summary Of Producer Sales From Dedications Committed Pursuant To Various Commission Orders Or Area Rate Opinions

	Applicable Commission Order		1971 thru 1973		
	Order No.	Date Issued	Anticipated Deliveries (MMcf)	Percent of Total	Wtd. Avg. Init. Price (c/Mcf)
Estimated Sales Under:					
1. Long Term Contracts					
Southern Louisiana	Opinion 598	7-16-71	663,266	21.34	25.88
Texas Gulf Coast	Opinion 595	5-6-71	116,447	3.75	22.71
Hugoton-Anadarko	Opinion 586	9-18-70	88,341	2.84	20.24
Permian Basin	Order R-389-A	7-17-70 1/	145,047	4.67	23.69
Other Southwest	Opinion 607	10-29-71	37,052	1.19	26.62
Rocky Mountain	Order 435	7-15-71	128,494	4.14	19.48
Appalachia	Order 411	10-2-70	15,626	0.50	31.55
Permian Basin	Opinion 662	8-7-73	3,309	0.11	34.91
2. Optional Pricing	Order 455	8-3-72	88,668	2.85	39.71
3. Emergency Procedures					
60 - Days	Order 418	12-10-70	376,000	12.10	37.35
180 - Days	Order 491	9-14-73	201,000	6.47	50.41
4. Limited Term Certif.	Order 431	4-15-71	906,000	29.16	36.63
5. Small Producer Contracts	Order 428-C	4-10-72	337,959	10.88	35.67
Total Aggregate Volumes			3,107,2[illegible]	100.0	32.85

Appendix G
Sheet 2 of 2

Docket No. R-389-B

FOOTNOTES: (To Appendix G, Sheet 1 of 2)

Note: The volume shown in the Anticipated Deliveries column is the 1971-3 summation of the anticipated annual sales volume as determined for each calendar quarter for Items 1, 2, 4 and 5. For Item 3 (Emergency Procedures) it is the 1971-3 summation of the total volume anticipated to be delivered during the period indicated and also determined for each calendar quarter.

1/ Sales authorized at rates in excess of Opinion No. 468 levels (Permian I) pursuant to Paragraph 12 of order issued July 17, 1970, in Docket No. R-389-A during the period ending with the issuance of Opinion No. 662 (Permian II).

Docket No. R-389-B APPENDIX H

EXPLANATION OF ILLUSTRATIVE DCF COSTING MODELS

Case I

In this case Park's basic model is used with the sole changes that staff pre-production expenses, based on a 485 Mcf./ft. productivity, are employed and that total price, net of state production tax, is found.

Pre-production expenses are:

Table 1

	Year	Staff Cost	Tax Credit	Net Invest.
Other Exploration	-4	2.62	1.194	1.426
Exploration Overhead	-4	.82	.3739	.446
Lease Acquisition	-3	3.83	a/	3.83
Dry Holes	-2	3.77	1.8096	1.9604
Successful Well & Recompletion Costs	-1	5.88	1.9757	3.9043
Other Production Facilities	-1	1.28	0	1.28
Lease Acquisition Tax Credit	-1	______	1.3788	-1.3788
Total		18.20	6.732	

a/ The lease acquisition tax credit is taken in year -1.

Because return on the pre-production expenses is calculated from mid-year we calculate the present value, at a 15% rate of return, of the expenses at mid-year of the first year of production.

Table 2

Year	Net Investment	Present Value at time .5
-4	1.872	3.274
-3	3.83	5.825
-2	1.9604	2.593
-1	3.8055	4.376
Total Present Value		16.068

The net cash flow per Mcf. is:

Table 3

Price - Royalty % times price	.84 Price
- Production operating expense	-3.10
- Interest on working capital	-1.14
- Regulatory expense	- .20
+ Net liquid credit	+3.89
- Tax liability offsetting the tax credit	-6.732
	.84 Price - 7.282

The present value of the net cash flow at the mid-point of the first production year is: (net cash flow per Mcf.) x Mcf./yr. x $\sum_{0}^{17} (\frac{1}{1.15})^i$ = (.84 Price - 7.282) x $\frac{1}{18}$ x 7.047 1/ = .3289 x Price - 2.851 which must equal the present value of the pre-production expense; i.e., 16.068 = .3289 x Price - 2.851 or

Price = (16.068 + 2.851)/.3289 = 57.5. Therefore, the price is 57.5¢/Mcf.

1/ The formula $\sum_{0}^{17} (\frac{1}{1.15})^i = \frac{1.15 - (\frac{1}{1.15})^{17}}{.15}$ aids the process of finding the 7.047 figure.

Case II

Staff's pre-production expenses, given productivity of 485 Mcf./ft., are reduced by allocating a pro rata share of 3¢ from flowing gas revenues to each component. Tax credits are taken on the actual outlays in the fashion advocated by Park. These expenses are computed and allocated as follows:

Table 1

	Year	Staff Cost	Pro rata Share of 3¢	Tax Credit	Net Invest.
Other Exploration	-3	2.62	.4319	1.1947	.9934
Exploration Overhead	-3	.82	.1352	.3739	.3108
Lease Acquisition	-2	3.83	.6313	a/	3.199
Dry Holes	-1	3.77	.6214	1.8096	1.339
Successful Wells & Recompletion	-1	5.88	.9692	1.9757	2.9351
Other Production Facilities	-1	1.28	.2110	0	1.069
Tax Credit on Lease Acquisition	-1	----	----	1.3788	-1.3788

a/ The lease acquisition tax credit is taken in the year -1.

Each year's expense is assumed to be incurred at mid-year and its present value, using a 15% rate of return, at the mid point of the first production year is obtained.

Table 2

Year	Net Investment	Present Value at time .5
-3	+1.3042	+ 1.9835
-2	+3.199	+ 4.2307
-1	+3.9643	+ 4.5589
		+10.7731

The next step is to find the net cash flow per Mcf. Because a price net of state production taxes is sought, those taxes are excluded. The net cash flow per Mcf. is equal to that for Case I less 3¢ for recovery of the investment from flowing gas revenues; that is, .84 Price - 10.282.

A 4% decline rate in production is assumed. Let Q_1 be production in the first year. Then, because a total of one Mcf. is to be produced, $1 = Q_1 \sum_{o}^{17} (\frac{1}{1.04})^i = Q_1(13.165668)$ or 2/ $Q_1 = .075955$. At a 15% rate of return (net cash flow/Mcf.) x

---

2/ $\sum_{o}^{17} (\frac{1}{1.04})^i = \frac{1.04 - (\frac{1}{1.04})^{17}}{.04}$

$Q_1 \sum_{o}^{17} (\frac{1}{1.04})^i (\frac{1}{1.15})^i$ = Present value of investment at time .5 or 3/ (.84 Price - 10.282).075955(5.8586) = 10.7731, so that Price x .84(.075955)(5.8586) = Price x .37379 = 10.7731 + 10.282(.075955)(5.8586) = 10.7731 + 4.5754 = 15.3485. Therefore, Price = 15.3485/.37379 = 41.06¢/Mcf.

3/ $\sum_{o}^{17} (\frac{1}{1.04})^i (\frac{1}{1.15})^i = \sum_{o}^{17} (\frac{1}{1.196})^i = \frac{1.196 - (\frac{1}{1.196})^{17}}{.196}$

Case III

In this case Staff's costs from the "Revised Update-High" are adopted, together with the price corresponding to the Staff's cost estimate of 42.74¢/Mcf., escalation of 1¢/Mcf. beginning in the second year and production at a constant rate over an 18-year depletion period. The "true yield" rate of return is found.

There are total pre-production expenses of 18.2¢ and a tax credit of 6.7327¢, as in Case I, which are assumed concentrated 1 1/2 years prior to the beginning of production. The present value at time .5 is

(1) $(18.2-6.7327)X(1+r)^2$,

where r is the rate of return.

The present value of the 1¢ escalation at time .5 is

$$(2)\quad \frac{(1-.16)}{18} \sum_{1}^{17} i\left(\frac{1}{1+r}\right)^{i}$$

where the (1-.16) accounts for royalty on the escalation. The contribution of the initial price of 42.74¢ is, where CF is the net cash flow per Mcf.,

$$(3)\quad \frac{(CF)}{18} \sum_{0}^{17} \left(\frac{1}{1+r}\right)^{i}$$

The value of CF, the net cash flow per Mcf., is calculated as in Case I. CF-= .84 Price - 7.282 = .84(42.74) - 7.282 = 28.6196.

The desired value of r, the rate of return, equates the sum of the quantities in (2) and (3) with that in (1). On choosing r = .1265, or 12.65%, we find from (1)

$$(18.2-6.7327)(1.1265)^{2} = 14.552$$

and from (2) and (3) 4/

$$\frac{.84}{18} \sum_{1}^{17} i\left(\frac{1}{1.1265}\right)^{i} + \frac{28.6189}{18} \sum_{0}^{17} \left(\frac{1}{1.1265}\right)^{i} = 14.523,$$ a

suitably close approximation of equality.

4/ $$\sum_{1}^{17} i\left(\frac{1}{1+r}\right)^{i} = \frac{1+r}{r}\left[1 - (n+1)\left(\frac{1}{1+r}\right)^{n} + n\left(\frac{1}{1+r}\right)^{n+1}\right]$$

Staff's costing, the associated price of 42.74¢, 1¢ escalation and constant takes entail, therefore, a true rate of return of 12.65%.

APPENDIX D

OPINION NO. 699-H OF THE FEDERAL POWER COMMISSION, OPINION AND ORDER ON REHEARING AFFIRMING IN PART AND MODIFYING IN PART AND DENYING IN PART PETITIONS FOR REHEARING (ISSUED DECEMBER 4, 1974)

[3520]*

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

OPINION NO. 699-H

Just And Reasonable National Rates For Sales of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973	)	Docket No. R-389-B

OPINION AND ORDER ON REHEARING AFFIRMING IN PART AND MODIFYING IN PART OPINION NO. 699 AND GRANTING IN PART AND DENYING IN PART PETITION FOR REHEARING

Issued: December 4, 1974

DC-56

*Transcript Page Number

[3521]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

[18 C.F.R. Part 2 (§§2.56, 2.56a, 2.66)]

Before Commissioners: John N. Nassikas, Chairman; Albert B. Brooke, Jr., Rush Moody, Jr., William L. Springer, and Don S. Smith.

Just And Reasonable National Rates for Sales of Natural Gas from Wells Commenced On or after January 1, 1973, And New Dedications Of Natural Gas to Interstate Commerce on or After January 1, 1973	)	Docket No. R-389-B

OPINION NO. 699-H

OPINION AND ORDER ON REHEARING AFFIRMING IN PART AND MODIFYING IN PART OPINION NO. 699 AND GRANTING IN PART AND DENYING IN PART PETITIONS FOR REHEARING

(Issued: December 4, 1974)

NASSIKAS, Chairman:

On June 21, 1974, the Commission issued its Opinion No. 699[1] determining and establishing a just and

1. ____F.P.C.____ (1974). Rehearing of Opinion No. 699 for purposes of further consideration was granted by the Commission's order of August 2, 1974. ____F.P.C.____, *amended,* ____F.P.C. ____ (August 12, 1974).

[3522]

reasonable national rate structure for post-December 31, 1972 sales of natural gas in interstate commerce.[2] Opinion No. 699-B, ____F.P.C. ____ (September 9, 1974), reinstituted with modifications the emergency sales provisions (18 C.F.R. §157.29) and the limited-term certification authority (18 C.F.R. §2.70 (b)(3)) which were terminated by Opinion No. 699.

Thirty-seven petitions for rehearing, reconsideration, and/or clarification of Opinion No. 699 were filed by natural gas producers, interstate pipelines, gas distributors, state agencies, a United States Senator, trade associations, and one industrial concern.[3] Twenty-three parties and groups of parties requested and presented oral argument before the Commission on August 22 and 23, 1974.[4]

Many of the petitions for rehearing simply reiterated contentions that were expressed in comments filed during the proceedings. We have, however, considered all arguments

2. Opinion No. 699-A, ____F.P.C.____ (August 2, 1974), modified the text of Opinion No. 699 and section 2.56(h)(1) of the regulations promulgated therein to provide (1) that sales formerly made under 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29, would be eligible for the prescribed national rate if a permanent sale of such gas was initiated on or after January 1, 1973, thereby eliminating the requirement that such sales be made pursuant to a contract executed on or after that date, and that (2) a renewal contract executed on or after January 1, 1973, qualified the continuing sale of such gas for the national rate regardless of the date of expiration of the former contract. See *infra* at 39-44.

3. A list of those persons filing such petitions is attached as Appendix A.

4. Persons presenting oral argument are listed in Appendix B.

[3523]

advanced by the applications, including those which were fully answered or otherwise disposed of in Opinion No. 699, and have made a number of modifications to the rate structure promulgated in Opinion No. 699.[5]

I.

THE USE OF RULEMAKING TO ESTABLISH JUST AND REASONABLE NATIONAL RATES

Two parties to this proceeding, the American Public Gas Association (APGA) and United States Senator James G. Abourezk, assert in their applications for rehearing that the Commission may not lawfully establish just and reasonable rates by the utilization of any procedures less strict than the formal adjudicatory procedures prescribed by the Administrative Procedure Act.[6] These assertions are contrary to established judicial precedent[7] and are, accordingly, rejected.

[3524]

APGA's contention that the Fifth Amendment to the Constitution requires the Commission to follow formal rulemaking proceedings in a ratemaking proceeding such as the subject one is erroneous and contrary to established precedent. There is no constitutional right to the formal procedures requested by APGA nor to any "particular form of procedure" which a party may desire. *National Labor Relations Board v. Mackay Radio & Telegraph Co.,* 304 U.S. 333, 351 (1938). "The requirements imposed by that [Fifth Amendment] guaranty [of due process] are not technical, nor is any particular form of procedure necessary." *Inland Empire District Council v. Millis,* 325 U.S. 697, 710 (1945); *Morgan v. United States,* 298 U.S. 468, 478, 481 (1936). Thus, since the Administrative Procedure Act "created safeguards even narrower than the constitutional ones,"[8] we must determine if the procedures followed herein comply with the requirements of the Natural Gas Act and the Administrative Procedure Act. If the constraints of the statutes are satisfied, then the constitutional inquiry is ended.

Both the United States Courts of Appeals for the District of Columbia Circuit and the Tenth Circuit have unequivocally held that the Federal Power Commission is not bound to observe the formal rulemaking procedures of sections 7 and 8 of the Administrative Procedure Act (5 U.S.C. §§556, 557) in establishing rates under the Natural Gas Act. *American Public Gas Association, et al. v. FPC,* 498 F.2d 718 (D.C. Cir. May 23, 1974); *Mobil Oil Corp. v. FPC,* 483 F.2d 1238, 1250-1251 (1973); *Phillips Petroleum Company v. FPC,* 475 F.2d 842, 851-852 (10th Cir. 1973). There is no doubt that the two courts have disagreed over the theoretical issue whether the minimal requirements of Section 553 of the Administrative Procedure Act will suffice in a Commission ratemaking

5. There are also a number of matters which have been clarified in response to questions pertaining to the rate structure and its application to natural gas producers, especially small producers.

6. 60 Stat. 241-242 (1946); 5 U.S.C. §§556, 557 (1970).

7. *United States v. Florida East Coast Ry., et al.,* 410 U.S. 224 (1973); *United States v. Allegheny-Ludlum Steel Corp.,* 406 U.S. 742 (1972); *American Public Gas Association, et al. v. FPC,* 498 F.2d 718 (D.C. Cir. May 23, 1974); *Mobil Oil Corp. v. FPC,* 483 F.2d 1238 (D.C. Cir. 1973); *Phillips Petroleum Co. v. FPC,* 475 F.2d 842 (10th Cir. 1973), *cert. denied,* 414 U.S. 1146 (January 14, 1974).

8. *United States v. Morton Salt Company,* 338 U.S. 632, 644 (1950).

[3525]

proceeding. That issue is not present in this proceeding, and APGA's assertion of "a split in the Circuits on this point" is misplaced.

In *Mobil v. FPC, supra,* there was no notice, no opportunity to submit data or comments with respect to the subject of rates, and the D. C. Circuit stated that "it appears probable that the FPC did not even comply with the minimal requirements of section 553." 483 F.2d 1238 at 1251 n. 39. The procedures in this case provided for the submission of two sets of initial and reply comments including such sworn testimony and data as the individual parties desired to bring to the Commission's attention, a public conference on the disputed issues of reserve additions and drilling footages, and oral argument upon Opinion Nos. 699 and 699-A. Thus, APGA cannot assert in good faith that it has been denied a "mechanism whereby adverse parties can test, criticize and illuminate the flaws in the evidentiary basis being advanced regarding a particular point," 483 F.2d 1238 at 1263.[9]

The *Mobil* case does not require the use of the formal rulemaking procedures under 5 U.S.C. §§556, 557 in this case as APGA so zealously asserts in its petition for rehearing.[10] Those procedures are required only where the underlying substantive statute compels that rules be made "on the record after opportunity for an agency hearing."

9. We note while APGA has consistently opposed the use of reserve additions as reported by the American Gas Association that no representative of APGA attended the public conference held in this proceeding. Nor did APGA avail itself of the opportunity to submit any testimony or data contradicting positions taken by adverse parties, but chose to rely solely upon statements of its counsel.

10. 483 F.2d 1238 at 1250-51.

[3526]

5 U.S.C. §553(c) (1970). The Supreme Court has held the absence of this language, while not absolutely controlling, is a strong indication that Congress did not intend that the formal procedures of sections 556 and 557 were to be mandated. *United States v. Florida East Coast Ry.,* 410 U.S. 224 (1973); *United States v. Allegheny-Ludlum Steel Corp.,* 406 U.S. 742 (1972).[11]

The "substantial evidence" requirement of the Natural Gas Act does not mandate that the formal procedures of sections 556 and 557 be followed in a ratemaking proceeding. The Court concluded in *Mobil* that "such complete adjudicatory procedures are not required." 483 F.2d 1238 at 1262.

Finally, the Commission's Rules of Practice and Procedure provide no support for APGA's position. Section 1.20(g) (18 C.F.R. §1.20(g)) merely provides for the "Presentation by the parties" when the Commission determines a formal hearing is required and initiates the same pursuant to Section 1.20(a) (18 C.F.R. §1.20(a)). Section 1.20(m) provides for procedures in rulemaking proceedings. 18 C.F.R. §1.20(m). Thus, it is clear that section 1.20 provides for the informal proceedings under 5 U.S.C. §553, the procedures followed in this proceeding, and the formal proceedings under 5 U.S.C. §§556, 557, without specifically requiring which of these procedures will be mandated in any given case.

11. These decisions and the *Phillips, Mobil,* and *APGA* decisions, *supra* n. 7, clearly show the error in Senator Abourezk's contention that we have "violated the congressional intent underlying the Natural Gas Act."

[3527]

In addition to the legal precedent supporting the establishment of national rates for sales of natural gas in interstate commerce in a rulemaking proceeding, there exists compelling public policy reasons for the utilization of such procedures in establishing rates on a national basis. That reason is the delay and uncertainty of the allowable rate levels, on the part of producers, pipelines, distributors, and the ultimate consumer, that accompanied the setting of rates on an area basis under traditional adjudicatory procedures. This delay and uncertainty reduces the commitment of capital to exploration and development efforts, compels the establishment of rates upon outdated records, and deprives consumers of incremental supplies of gas as a result of unrealistically low rates geared to out-moded historical costs. Clearly these results are not in the public interest and should be reduced to the extent possible under the Natural Gas Act consistent with providing all parties to the proceeding before the Commission a fair opportunity to present their views and cases to the Commission.

One need look no further than the recent Supreme Court decision in *Mobil Oil Corp., et al. v. FPC,*[12] which after 13 years finally concluded the proceedings to establish rates for the Southern Louisiana Area, to observe the delay and uncertainty that have accompanied the traditional adjudicatory method of setting area rates. This proceeding was commenced by the Commission on May 10, 1961,[13] and the Commission's opinion issued on September

12. 42 U.S.L.W. 4842 (U.S. June 10, 1974).

13. *Area Rate Proceeding, et al. (Southern Louisiana Area),* Docket No. AR61-2, 25 F.P.C. 942 (1961).

25, 1968,[14] with rehearing denied on May 9, 1969.[15] The Court of Appeals for the Fifth Circuit affirmed the Commission's decision, but held that evidence on the supply of and demand for natural gas which had come into being after the Commission's decision required that the Commission have the power to reopen the case if it found a necessity

[3528]

for such action.[16] Upon receipt of the Fifth Circuit's mandate, the Commission consolidated the proceedings in Docket AR61-2 with the second round proceedings in Docket No. AR69-1, and provided for further hearings.[17] Following these hearings and a number of settlement conferences, the proposed settlement which became one of the major underpinnings of Opinion No. 598 was presented to the Commission on March 15, 1971. Briefs were filed with the Commission, and on July 16, 1971, Opinion No. 598 was issued.[18] This opinion completely revised the rates and refunds required by Opinion No. 546 and prescribed new rates and incentive refund work off and contingent escalation provisions. The Fifth Circuit

14. 40 F.P.C. 530 (1968), *amended,* 41 F.P.C. 301 (1969).

15. 41 F.P.C. 616, 617 (1969).

16. *Austral Oil Co., et al. v. FPC,* 428 F.2d 407, *reh. denied,* 444 F.2d 125, *cert. denied sub nom. Municipal Distribution Group v. FPC,* 400 U.S. 950 (1970).

17. *Area Rate Proceeding (Offshore Southern Louisiana, Federal Domain And Disputed Areas),* 41 F.P.C. 378 (1969). This proceeding was expanded to include a review of all Southern Louisiana rates by order of December 15, 1969. 42 F.P.C. 1110 (1969). The proceedings were consolidated by order of December 24, 1970. 44 F.P.C. 1638.

18. 46 F.P.C. 86, *reh. denied,* 46 F.P.C. 633 (1971).

affirmed the opinion in full on April 16, 1973,[19] and it was, in turn, finally affirmed by the Supreme Court on June 10, 1974.

To those who believe that the Southern Louisiana proceedings are simply an aberration caused by a unique set of circumstances, it is helpful to review the record of the other area rate proceedings. These proceedings also demonstrate an inordinate amount of delay where adjudicatory procedures were followed, and a much more rapid resolution of those proceedings in which rule-making procedures were adopted.

[3529]

The first Permian Basin proceeding commenced on December 23, 1960,[20] with the Commission's decision being rendered on August 5, 1965,[21] and affirmed by the Supreme Court in 1968.[22]

The second Permian proceeding was initiated on June 17, 1970,[23] and concluded by Opinion No. 662.[24] The petitions for review of this decision were withdrawn under Court orders of August 21 and 30, 1974.[25]

19. *Placid Oil Co., et al. v. FPC,* 483 F.2d 880 (5th Cir. 1973).

20. *Area Rate Proceeding, et al.,* 24 F.P.C. 1121 (1960).

21. 34 F.P.C. 159, *reh. denied,* 34 F.P.C. 1068 (1965).

22. *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968).

23. *Area Rate Proceeding (Permian Basin Area II),* 43 F.P.C. 899 (1970). The record in the Southern Louisiana proceedings were incorporated as part of the record of this proceeding in an effort to expedite a final resolution of the case. 43 F.P.C. at 901.

24. 50 F.P.C. 390 (August 7, 1973), *reh. denied,* 50 F.P.C. 932 (September 28, 1973).

25. *Chevron Oil Co., Western Division, et al.* (9th Cir., Nos. 73-2861, *et al.,* filed September 28, 1973).

The Hugoton-Anadarko proceeding[26] was commenced on November 27, 1963, along with the Texas Gulf Coast proceeding.[27] Joint hearings were held on common issues and the cases severed for further hearings directed to

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issues related to the specific area. On September 18, 1970, the Commission approved a settlement in the Hugoton-Anadarko proceeding,[28] which was affirmed on July 31, 1972.[29]

The Commission finally rendered its decision in the Texas Gulf Coast proceeding on May 6, 1971.[30] This decision was reversed by the D.C. Circuit on August 24, 1973,[31] and that decision was vacated and remanded by the Supreme Court on June 17, 1974.[32]

The Other Southwest proceeding was commenced on February 28, 1967;[33] the Commission's decision was issued on October 29, 1971, and affirmed by the Fifth Circuit on June 8, 1973. Certiorari was denied by the Supreme Court on June 17, 1974.[34]

26. *Area Rate Proceeding, et al. (Hugoton-Anadarko Area),* 30 F.P.C. 1354 (1963).

27. *Area Rate Proceeding, et al. (Texas Gulf Coast Area),* 30 F.P.C. 1354 (1963).

28. 44 F.P.C. 761, *reh. denied,* 44 F.P.C. 1434 (1970).

29. *California v. FPC,* 466 F.2d 974 (9th Cir. 1972).

30. 45 F.P.C. 674, *reh. denied,* 46 F.P.C. 827 (1971).

31. *Public Service Commission for the State of New York, et al. v. FPC,* 487 F.2d 1043 (1973).

32. *Shell Oil Co. v. Public Service Commission of the State of New York,* 42 U.S.L.W. 3686 (U.S. June 17, 1974).

33. 37 F.P.C. 400 (1967).

34. *Area Rate Proceeding, et al. (Other Southwest Area),* 46

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With the commencement on October 16, 1969,[35] of proceedings for the Appalachian and Illinois Basin area, the Commission initiated its use of rulemaking to establish area rates. This proceeding was concluded on October 2, 1970, with the issuance of Order No. 411,[36] which was not appealed.

Initial rates for post June 17, 1970, sales made in the Rocky Mountain area were established by Order No. 435, which was issued on July 15, 1971.[37] This order was affirmed on May 23, 1974.[38] Opinion No. 658 established just and reasonable rates for Rocky Mountain gas sold under contracts dated prior to October 1, 1968, and made the Order No. 435 rates applicable to contracts dated between October 1, 1968, and June 17, 1970.[39] The pe-

F.P.C. 900, *reh. denied*, 47 F.P.C. 99 *affirmed sub nom., Shell Oil Co., et al. v. FPC*, 484 F.2d 469 (5th Cir. 1973), *cert. denied, sub nom., Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 3688 (June 17, 1974).

35. *Area Rates For The Appalachian And Illinois Basin Areas*, 34 *Fed. Reg.* 17341 (1969).

36. 44 F.P.C. 1112, *amended*, Order No. 411-A, 44 F.P.C. 1334, *reh. denied*, Order No. 411-B, 44 F.P.C. 1487 (1970).

37. *Initial Rates For Future Sales Of Natural Gas For All Areas*, 46 F.P.C. 68, *reh. denied*, 46 F.P.C. 620 (1971). These proceedings had commenced with a notice of rule-making in Docket No. R-389 on June 17, 1970. 35 *Fed. Reg.* 10152; *see also*, 35 *Fed. Reg.* 11683 (1970).

38. *American Public Gas Association, et al v. FPC*, 498 F.2d 718 (D.C. Cir. May 23, 1974).

39. *Area Rates For The Rocky Mountain Area*, 49 F.P.C. 924, *reh. denied*, 49 F.P.C. 1279 (1973), appeal dismissed *sub nom. Exxon Corporation v. FPC* (D.C. Cir. No. 73-1854, dismissed February 22, 1974). This proceeding had commenced July 15, 1971, with a notice of rulemaking, 46 F.P.C. 43, and the Commission's power to proceed under 5 U.S.C. §553 (1970) was affirmed in *Phillips Petroleum Co. v. FPC*, 475 F.2d 842 (1973), *cert. denied*, 414 U.S. 1146 (January 14, 1974).

titions for review of Opinion No. 658 were withdrawn by the petitioners on February 22, 1974.

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The present gas shortage and the need for vastly expanded exploration and development programs to meet future demand dictates that the establishment of rates for "wellhead sales"[40] of natural gas in interstate commerce not be unduly delayed and that administrative procedures such as rulemaking be utilized to prevent the prescribed rates from becoming stale before they are effective. Moreover, the continually increasing competition from the unregulated intrastate market demands that the interstate market have the ability to respond as may be necessary to assure the maintenance of adequate natural gas service to the customers of the interstate pipelines.[41]

This procedural flexibility is available to this Commission through the rulemaking procedures that have been followed in the instant case. The Commission in slightly over one year from the commencement of the proceeding was able to prescribe a single uniform national rate that will enable interstate pipelines to more effectively compete

40. A "wellhead sale" is the sale of natural gas by a natural gas producer (including a pipeline affiliate) to another producer or an interstate pipeline. Pipeline production is also eligible for the rate established for "wellhead sales" pursuant to sections 2.56a and 2.66.

41. While we have often stated our views that regulation of "wellhead sales" made in interstate commerce should be terminated as to new sales of natural gas subject to review by the FPC to prevent abuses should they occur, it is necessary to note that the Natural Gas Act requires that sales of natural gas for resale in interstate commerce must be made at rates that are "just and reasonable." *FPC v. Texaco Inc.*, 42 U.S.L.W. 4867 (U.S. June 10, 1974). Under such constraints, it has not been demonstrated by substantial evidence that intrastate prices are just and reasonable.

with intrastate purchasers for new supplies of natural gas. Had this case been conducted pursuant to

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the traditional adjudication procedures, it is most likely that a final decision in this proceeding would not yet have been rendered, and the now superseded area rates, which had proven inadequate, would still govern interstate sales of natural gas. Thus, we are of the opinion that the expeditious resolution of this case has improved the regulatory climate and increased the attractiveness of the interstate market for natural gas producers, especially in light of the modifications adopted in this opinion.

II

RATE DESIGN

A. *Cost Factors*

The cost findings in Opinion No. 699 have been vociferously attacked by a number of parties to this proceeding as being too low[42] or too high.[43] For the reasons hereinafter set forth, we believe that the

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Commission should implement the traditional area rate

42. Indicated Producer Respondents (Producers), all producer respondents filing individual comments, Columbia Gas System Companies and other interstate pipeline companies, the Interstate Natural Gas Association of America (INGAA), Associated Gas Distributors (AGD), United Distribution Companies (UDC), Southern California Gas Company, and General Motors Corporation. Other parties filed specific comments regarding costs for the Appalachian-Illinois Basin Area.

43. The American Public Gas Association (APGA) and Senator James G. Abourezk.

costing methodology adopted in *Permian I*[44] and utilized since that time with the continuing approval of the Courts.[45] As a basis for prescribing just and reasonable rates, we adopt herein (1) a discounted cash flow (DCF) costing format to assure within reasonable limits that the rates found under the Permian methodology will produce a 15 percent rate of return over the life of the investment, and (2) drilling costs (both successful well and dry hole) trended by the use of least squares regression analysis to derive a range of reasonable costs.

We find that supplementary cost analysis necessary to assure that the rate allowed for new gas supplies adequately reflects the true cost of those supplies. We believe that the *Permian* methodology adjusted by applying a DCF analysis to produce a true yield of 15 percent over the life of the investment and further tested by the use of trended drilling

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costs will establish a more reliable foundation for a predictive just and reasonable rate than will the exclusive use of the *Permian* methodolgy standing alone. If the

44. *Permian Basin Area Rate Proceeding,* 34 F.P.C. 159, (1965), *affirmed, Permian Basin Area Rate Cases,* 390 U.S. 747 (1968).

45. *Area Rate Proceeding (Permian Basin Area II),* 50 F.P.C. 390, reh. denied, 50 F.P.C. 932 (1973), appeal dismissed *sub nom. Chevron Oil Co., Western Division, et al. v. FPC,* Nos. 73-2861, et al., 9th Cir., motions to withdraw appeals granted August 21 and 30, 1974; *Area Rate Proceeding, et al. (Southern Louisiana Area),* 46 F.P.C. 86 (1971), *affirmed sub nom. Mobil Oil Corp. v. FPC,* 42 U.S.L.W. 4842 (U.S. June 10, 1974); *Area Rate Proceeding, et al. (Texas Gulf Coast Area),* 45 F.P.C. 671 (1971), *reversed, Public Service Commission of the State of New York v. FPC,* 487 F.2d 1043 (D.C. Cir. 1973), *cert. granted, vacated* and *remanded, Shell Oil Co. v. Public Service Commission of the State of New York,* 42 U.S.L.W. 3686 (U.S. June 17, 1974).

basis for prescribing just and reasonable rates is a more reliable evidentiary foundation so that producers may reasonably anticipate a 15 percent return on their investment, the rates established herein should meet our objective of encouraging increased future drilling efforts and the discovery of incremental gas supplies to avert ever deepening natural gas shortages. Without endorsing the arguments for or against DCF costing that have been made by the participants to this proceeding, we find that the DCF analysis[46] is necessary to make reasonably certain that the end result of a 15 percent return will be attained without the attrition inherent in the traditional *Permian* methodology and that the *Permian* methodolgy adjusted by the DCF analysis and supplemented by trended cost data is the most reliable basis for forecasting a reasonable rate structure.

Unlike a pipeline or an electric utility that may go into the bond market to raise money for the financing of major new projects, the typical natural gas producer depends upon internally generated funds and equity capital.[47] Because of the heavy reliance upon internally generated funds and equity capital, the producer is faced with the need to earn a return sufficient to maintain the attractiveness of its natural gas operations as compared to other alternative investments. If the natural gas producer does not earn a return on its natural gas operations which is equivalent to the return it can earn on alternative investments, it will invest its profits in those more attractive

46. The basic DCF formats are set out in Appendix H to Opinion No. 699, _____F.P.C._____.

47. The typical producer maintains approximately 76 percent of its capital structure as common equity with long-term debt accounting for 23 percent of the total capital and preferred stock accounting for under one percent. *See infra* at 33.

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investments rather than in expanded natural gas operations. The DCF methodology is designed to evaluate the price required to yield a given rate of return over the life of the project. It recognizes the fact that there is a time value which can be placed upon capital and that cash flow must be at a level necessary to produce the anticipated return.

The DCF methodology reflects the cost of capital by allowing a return on all invested funds. The *Permian* costing format requires that dry hole and exploration expenditures be expensed and recovered through production. The *Permian* formula is explicable only by an assumption that the dry hole allowance in the price of existing production in each year is in the aggregate sufficient to pay for or "expense" the total dry hole costs for that year. This assumption may or may not have ever been correct for a given producer. However, such an assumption today is contrary to the public interest in two related respects. First, it provides a disincentive to existing producers to increase investment in exploration and development and to incur the concomitant dry hole expense. The perpetuation of such disincentives would frustrate the fundamental national goal of achieving a greater degree of energy self-sufficiency. Second, the assumption and, consequently, the methodology is discriminatory to new market entrants who have no flowing gas against which to "expense" the dry hole costs. Today, the price of each Mcf of new gas must fully reflect the cost of finding and producing that gas and we find that the *Permian* formula does not adequately achieve that goal. If the recovery of such funds is to be permitted only over the depletable life of the project, then a return must be

allowed on these costs just as it is allowed for successful wells.

Several participants[48] urge that we correct the deficiency of no return on dry holes by adopting their proposed full cost accounting format. This full cost accounting methodology includes the dry hole costs as part of the net investment base upon which a return is computed under the *Permian* costing methodology, and would yield a rate level ranging from approximately 49 cents per Mcf to slightly over 56 cents

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per Mcf.[49] We decline to adopt their concepts of full cost accounting since it is our opinion that the DCF analysis correctly applies the principles of a return on dry hole costs and is a more reliable methodology for testing the validity of the prescribed just and reasonable rates. We will, therefore, adopt the DCF approach in testing the validity of the rates prescribed in this opinion rather than the suggested full cost accounting methodology.

While there may be certain informational gaps in the record as to the timing of pre-production expenditures and production of the gas discovered, we believe that the record as a whole permits us to make reasonable assumptions as to the timing of expenditures. We conclude that the timing pattern utilized in Case II of Appendix H to Opinion No. 699[50] is the most reasonable assumption that

48. Pennzoil Company, *et al.*, The Rodman Corporation, Tenneco Oil Company, and Texasgulf, Inc.

49. See the exhibits presented in oral arguments by The Rodman Corporation, *et al.*, for the derivation of these costs.

50. ____F.P.C.____.

may be made on the basis of this record. This pattern shows that the weighted average lead time from the expenditure of funds to the commencement of production is approximately 1.6 years which compares favorably with our conclusion in Opinion No. 699 that the average lead time was approximately 1.5 years.[51]

In utilizing the DCF analysis, we will retain the basic derivation of the various cost components adopted in Opinion No. 699 and other cases. We shall also continue to rely upon the statistical data sources utilized in the past cases for such sources are "well recognized and authoritative." Moreover, the comments of APGA and Senator Abourezk to the effect that we may not rely upon statistical data gathered and published by natural gas industry sources are truly misplaced in this proceeding for that issue has been resolved in favor of the Commission by the Courts. *Permian Basin Area Rate Case, supra; Placid Oil Co., et al. v. FPC,* 483 F.2d 880 (5th Cir. 1973), *affirmed, Mobil Oil Corp. v. FPC, supra.* Their comments regarding the net liquid credit have been considered. Again, taken in context, the value we assigned to the net liquid credit is reasonable in light of our utilization of drilling cost data for 1972 and an average productivity based upon the years 1966 through 1972, inclusive, as the basis for the cost computations and rate determinations.

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Rather than review each individual component of the detailed cost analysis set forth in Opinion No. 699, we shall concentrate upon the major variables such as drilling costs, productivity, rate of return, and the modifica-

51. ____F.P.C.____, Opinion No. 699 at 71-72.

tions required by the adoption of DCF costing to demonstrate the reasonableness of the costs and rates determined in this opinion.

With respect to the costs determined in this opinion, a range has been adopted which utilizes untrended 1972 cost figures as the low end of the range and trended drilling costs for the high end of the range. This range in conjunction with our cost findings based on *Permian* methodology tested by DCF analysis will provide a reasonably reliable estimation of the cost of new gas supplies, and it recognizes the fact that the drilling cost data available to the Commission is data for a past period which may not be truly representative of future costs.

1. *Drilling Costs*

Both the Producers and UDC allege that the Commission erred in failing to trend drilling costs to allow for inflation since the 1972 drilling costs were reported by the Joint Association Survey (JAS). There is no error in the Commission's decision to use 1972 JAS drilling costs without trending to determine the low side of the cost range adopted herein. Such costs, in an era of rising costs provide a base line, but only a base line, upon which to determine rates. We have determined that the upper end of the cost range used to determine rates should be based upon drilling costs as trended by the application of regression analysis.

Trended drilling costs for 1973 were developed from a least squares analysis of actual per foot drilling costs for successful wells and dry holes for 1963 through 1972. This technique indicates that trended successful well cost per foot will be $29.83 and that trended dry hole cost per foot will be $16.69.

These trended costs will be used to develop the high side of a reasonable cost range because they are more likely to be representative of future periods than are drilling costs for a past year, even the most recent year.

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2. *Productivity*

a. *Reserve Additions*

Again, the Producers and UDC are the major parties objecting to our productivity computations.[52] These parties allege that we have committed error by using average productivity for the most recent seven-year period (1966-1972) to determine costs. Both the Producers and UDC support productivity findings in the range of 350 to 400 Mcf per foot drilled on the assumption that productivity levels for the most recent three or four years demonstrate a definite downward trend which is not accounted for in the productivity findings of Opinion No. 699. Quite the contrary is true for the most recent seven-year period. It was adopted as the basis upon which to compute productivity because we conclude that this period would be most representative of future drilling efforts in light of recent productivity trends.

Past area rate cases computed productivity factors upon the average for the longest time series available; that is, for the period 1946 to the most current year for which reserve additions and drilling footages were available. This policy was not completely unrealistic prior to 1968 when reserve additions first dropped to an extremely

52. A number of parties made specific objections to our inclusion of the Appalachian-Illinois Basin Area within the scope of the national rate and recommended the establishment of a separate rate based upon that area's unique characteristics. *See infra* at 65-66.

low level which has continued through 1973.[53] In part, the extremely low productivities since 1969 are due to net negative revisions being reported

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by the American Gas Association for those years. However, even after the exclusion of all revisions - negative or positive - the data still show a marked drop in reserve additions and productivity levels starting in 1968.[54]

It is to this decline that the Commission's attention must be directed for there are a number of questions regarding the decline which must be answered. Will the extremely low level of new additions experienced from 1968 through 1973 continue into the future? Are the productivity levels reported for 1968 through 1973 indicative of future productivity levels [55] Are there factors which may improve the level of new reserve additions and productivity in the future?

The expansion of gas-well drilling activity which began in 1972 and carried through the first six months of 1974 should increase the volume of new reserve additions in the near future. The reserve additions data for 1966 through 1972 show a significant drop for new field discoveries for the period 1968 through 1972 with extensions showing a decline for 1968 through 1973 over 1966 and 1967. New

53. See Table I. This table covers only the years 1966 through 1973 since reserve additions were not broken out into revisions, extensions, new field discoveries, and new reservoir discoveries in old fields prior to that year.

54. Table I.

55. The productivity factor for 1973 is based upon preliminary drilling footage statistics and is subject to the possibility of modification when the final statistics are reported.

reservoir discoveries in old fields demonstrate a very erratic pattern for the entire period (1966-1973) with no discernable trend. Revisions show a precipitous drop after 1968 which accelerated in 1973. For 1966 to 1968, net revisions increased from a positive 3 Tcf[56] per year to a positive 4 Tcf per year. For 1969, net revisions were a negative 1.4 Tcf per year and this increased to a negative 1.9 Tcf for 1972. In 1973, net revisions increased

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to a negative 5.3 Tcf per year, nearly a three-fold increase. For present purposes, it is the trends in new field discoveries and new reservoir discoveries in old fields that are of the main interest.[57]

For the period 1968 through 1972, new field discoveries averaged approximately 1.4 Tcf per year compared to 2.8 Tcf per year for 1966 and 1967. This level increased to 2.0 Tcf in 1973 indicating that the expanded drilling programs were beginning to have an effect upon reserve additions. With the increased leasing of acreage in the offshore Federal domain starting in late 1972, it can be expected that the level of new field discoveries should increase significantly over the levels recorded for 1968 through 1972 in the 1973-1974 period. Thus, the use of the most recent three to four year period prior to 1973 would probably understate the level of new field discoveries for the near future.

The trend for new reservoir discoveries in old fields is no trend at all. The reported new volumes for this class of discoveries declined from 1966 through 1969 only to

56. Tcf stands for trillion cubic feet.

57. See Table I.

increase for two years before entering another declining mode. Given the trend for 1966 through 1973, it can be expected that the volumes attributable to this class of discoveries should again increase in 1974 or 1975. Here, the average for the eight year period (approximately 2.9 Tcf per year) should approximate or be somewhat less than the level that will be experienced in the near future.

Extensions demonstrate a discrete drop from a level of approximately 8 Tcf per year prior to 1968 to a level of approximately 5.3 Tcf after that year. Since 1973 extensions (5.3 Tcf) were substantially equivalent to the average for the previous five years, it would be easy to conclude

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that this level should continue for the near future. We would agree were it not for the increase in drilling activity since 1972. A careful analysis of the data on extensions results in the conclusion that this level may not be truly representative of future extensions. As new field discoveries increase the level of extensions will probably increase. New field discoveries increased in 1973 so it is probable that the level of extensions will increase in 1974 or 1975 unless new field discoveries again decline. Given the nature of the relationship between extensions and new fields and reservoirs, the present level of reported extensions is probably understated for the future and some allowance should be made for growth in this classification.

Revisions present the most difficult problem because it is extremely difficult to determine the relationship between revisions and drilling. Indeed, the AGA defintion of revisions indicates to a certain extent that revisions

are dependent upon production data in computing the magnitude of the revisions.

> The drilling of additional wells in a reservoir not only delineates the productive area but also provides additional basic geological and engineering data. Estimates of porosity, interstitial water, pay thickness and other reservoir factors may be revised by new data. Analysis of the producing history of a reservoir, including production of oil, gas and water, and pressure performance results in more accurate concepts concerning the producing mechanism, recovery efficiency and the performance of the reservoir. The composite of this new and improved information will yield more precise estimates of the ultimate recoveries and remaining reserves and result in revisions to previous estimates. Changes in reserve
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> [3543]
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> estimates brought about [by] the application of cycling and other recovery techniques are included in the revision to reserves. Also, changes in reserves resulting from a reduction in the estimate of the proved area are included in revisions.

Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1973, Volume 28, June 1974, published jointly by the American Gas Association, the American Petroleum Institute, and the Canadian Petroleum Association. Thus, we must determine the extent to which revisions are the result of drilling and which are the result of additional production

experience, as well as the date of discovery of the reservoirs to which revisions are attributable.[58]

Because the AGA reserve reports do not classify revisions by the year in which the reservoir was discovered, it is impossible to determine which revisions should be included in the total reserve additions for computing productivity because of the age of the underlying reservoir. It appears probable that at least a substantial portion of the large negative revisions which have been reported in recent years relate to older reservoirs which are being updated to account for production. The *National Gas Reserves Study* noted that in many of the Texas Gulf Coast fields "the A.G.A. seemingly was either still based on volumetric calculations or production

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curves which had not been updated."[59] Moreover, the AGA reported with respect to 1973 reserve additions the following information on negative revisions:

> Negative revisions of prior estimates were reported for both Texas and Louisiana. These downward adjustments are based primarily on data obtained from continuing production experience. These data indicate a greater loss of pressure with production than had been anticipated.[60]

These sources indicate to us that the substantial negative revisions of recent years should be partially discounted as non-recurring adjustments that will not be repeated in future years.

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58. The effect of revisions for the eight-year period (1966-1973) is shown in Table I to this opinion.

59. FPC National Gas Survey, *National Gas Reserves Study* at 16, May 1973.

60. American Gas Association News Release, March 28, 1974.

Having determined that the significant negative revisions of recent years will probably not be repeated in the future because of the probable nature of the revisions, we must determine whether net revisions will continue to be negative or positive and the most reasonable volumes which will be attributable to this class of reserve additions. The reported data for 1966 through 1973 are not very helpful. For 1968 through 1973, positive revisions increased from 4.3 Tcf in 1966 to 6.2 Tcf in 1968 and then declining to 1.4 Tcf in 1973. During this same period, negative revisions increased from 1.3 Tcf in 1966 to 6.8 Tcf in 1973, with the most significant increase coming in 1973 when negative revisions increased 3.4 Tcf over the levels reported the two previous years. See Table II.

It is significant in evaluating revisions that there have been two abrupt changes in the pattern of reported revisions. The first occurred in 1969 when positive

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revisions dropped from an average of 5.4 Tcf per year for the previous three years to a level of 1.4 Tcf. See Table II. The second change was the dramatic increase of negative revisions in 1973 over the prior years - this increase was in the order of 3.7 Tcf when compared to the three prior years. See Table II. Given these abrupt changes, it is probable that positive revisions will again increase and that the level of negative revisions will decrease. We are, however, unable to quantify the potential changes in the level of future revisions.

In summary, we conclude that reserve additions for the most recent years are understated due to negative revisions relating to the updating of reserve estimates for

older reservoirs to reflect "continuing production experience," and a lower than normal level of new field and new reservoir discoveries resulting from decreased leasing in the offshore Federal domain in the late 1960's. The increased Federal leasing in 1973 and 1974 along with a decline in negative revisions will increase total reserve additions and result in improved productivity in the next several years.

Before leaving the subject of reserve additions and productivity, there is one final matter which deserves a reply. The Producers' contend that the Commission erred in its "statement . . . that the Producers did not submit any mathematical analysis of anticipated future productivity . . . is contrary to the record."[61] We note that Mr. Roe's own description of his study indicates that the study is limited to exploratory drilling, and does not include the effect of developmental drilling. Since Mr. Roe omitted an indispensable component in predicting future productivity, his study is not a credible mathematical model upon which the Commission may rely. Mr. Roe states:

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> It should be carefully noted that this method has application only to the portion of annual reserve additions attributable to newly discovered fields and certain newly discovered reservoirs.[62]

Thus, it appears that Mr. Roe has concentrated his focus upon only part of the total picture. The qualifying state-

61. Application For Rehearing of Indicated Producer Respondents, at 22 n. 22.

62. Response Of Indicated Producer Respondents To Notice Of Proposed Rulemaking And Order Prescribing Procedures, Appendix D at 2, May 16, 1973.

ments in Mr. Roe's comments of May 7, 1974,[63] do not cure the deficiencies in Mr. Roe's presentation.[64] An analysis so limited cannot serve as the basis for computing anticipated future productivity and the establishment of just and reasonable national rates.

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b. *Drilling Footages*

The rather dramatic increase in gas well drilling footage for 1973[65] is also in part responsible for the decline in productivity for that year. The data for the first six months of 1974 indicates that 1974 footage may increase approximately 24.3 percent above 1973 levels[66] for a total of over 44,000,000 feet.

63. Joint Comments Of Indicated Producer Respondents, Appendix I at 9-10.

64. We note that Mr. Roe's analysis reaches conclusions similar to those reached by United Distribution Companies witness Ogden. *See* Comments Of United Distribution Companies In Response To Notice Issued March 21, 1974 (Separate Appendix Prepared By William J. Ogden), May 7, 1974. Mr. Ogden bases his studies upon productivity trends of the most recent years on the assumption that productivity will continue to decline in the future.

Mr. Ogden's comments attached to UDC's petition for rehearing which suggest that drilling costs must be adjusted in order to conform to the productivity level selected by the Commission have no basis in the evidence of this proceeding and are rejected.

65. The increase of 1973 footage over 1972 footage is approximately 33.1 percent based upon preliminary footage data for 1973.

66. Preliminary data for the first six months of 1973 and 1974.

Year	Footage Drilled
1973	15,936,742
1974	19,805,833

VIII *Quarterly Review of Drilling Statistics for the United States, Second Quarter, 1974,* No. 2, American Petroleum Institute (August 1974).

This increase in drilling footage will lower productivity unless reserve additions also increase. Since our evaluation of the various components of total reserve additions indicates that they should increase sufficiently to offset the increased drilling footage, there should be no material drop in productivity levels in the near future. Some particular producing areas may experience small productivity declines, but others should show increases as expanded drilling efforts begin to disclose new fields and reservoirs.

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3. *Rate Of Return And The Rate Base*

The issues of the appropriate rate of return on the productive investment and the components to be included in the rate base are interrelated and will be considered together in this opinion on rehearing. Most of the contentions of the Producers and others challenging the rate of return allowed and the exclusion of dry hole costs from the rate base were fully answered in Opinion No. 699[67] and need not be repeated here.

a. *The Rate Of Return*

The Producers specifically, and others generally, allege that the 15 percent rate of return allowed by Opinion No. 699 is inadequate. It is urged that the rate is inadequate because of rising capital costs, inflation, and the natural gas shortage, and that rates of return of 15 to 18 percent after taxes on a discounted cash flow basis are required. The Producers also urge that they will not be permitted to earn the full 15 percent return allowed by the Commission. These contentions are erroneous as they

67. ____F.P.C.____, ____, Opinion No. 699 at 59-70.

fail to consider the fact that the rate allowed for non-associated gas is also allowed for associated and dissolved gas and for expiring contracts where a new contract is executed[68] thereby increasing the total return to natural gas producers selling gas in interstate commerce. Moreover, these contentions ignore the escalations provided by this

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opinion which further increase the return to the producer.[69] When all of these factors are evaluated, it cannot be said that the total return allowed by the Commission is not within a permissible "zone of reasonableness."[70]

We note that all of these factors are components of a total rate design and that it is impossible to single out any one component of the rate design as being unreasonable without considering the relationship of that component to the total. *Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974). When the rate of return allowed by Opinion No. 699 and this opinion are so considered, it cannot be said in good faith that the return allowed is insufficient or that the order "is unjust and unreasonable in its consequences." *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944); *see also, Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968); *Mobil Oil Corp. v. FPC, supra*, slip opinion at 19-23.

68. The contracts which are eligible for this rate are described *infra* at 40-44.

69. The producers are further protected from the attrition of their return by the Biennial review provisions prescribed in this opinion. *See* 50-54 *infra*.

70. *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585 (1942).

Before proceeding to an analysis of the appropriateness of a 15 percent rate of return, we are faced with the Producers' contention that they "are confronted with data not contained in the record." This data which comprised Appendix E of Opinion No. 699 set forth a study of the rates of return earned by various industrial groups in recent years. Such data is available to the public from widely recognized financial sources which this Commission may consider when it establishes rates. Thus, we find the Producers' contention pertaining to the extra-record nature of this data is meritless and it is rejected.

In general, the Producers' and UDC's main objections to the rate of return findings in Opinion No. 699 are the

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Commission's alleged failure to consider the evidence presented by the Producers' witnesses, Dr. Ezra Solomon and Kenneth E. Hill. This evidence was considered and evaluated by the Commission, but not adopted, and accorded the healthy skepticism that all evidence introduced by any party in a proceeding before the Commission receives before a decision is made. The FPC's function is to carefully weigh all evidence on all issues especially critical issues such as rate of return in order to protect the public interest. The Commission is, therefore, not required to treat as conclusive or controlling the evidence of any party. Such is the case of the evidence presented with respect to the rate of return in this case.

A fifteen percent rate of return is not unduly low in light of current financial conditions. While it is true that interest rates on short-term borrowing and long-term debt have increased significantly in the 1973-74 period it is not unreasonable to assume that these rates will decline over

time. We can to a certain extent discount these recent increases in evaluating the return allowed on long-term capital investments. The return on this investment must be a return that will attract capital for long-term investment. Because of the nature of the investments, there are different motivations which lead an investor to choose one over the other and it is impossible to equate the return on one with the return on the other. The best analysis that can be made is a comparison of the two. The long-term investment in gas exploration ventures which entail a certain degree of risk will necessarily have to provide a greater return than a short-term security that entails almost no risk. The dispute in this case is the difference that is required to make the long-term venture attractive to investors.

While historic levels of return for natural gas producers have been below the levels required to finance the

[3551]

necessary exploration programs, it has not been demonstrated by substantial evidence in the record of this proceeding that the allowed rate of return is inadequate. What has been demonstrated is the fact that the rates which had been determined in the prior area rate proceedings are too low and too far out of date. Had the Commission promptly determined, and then adequately reviewed rates in these earlier proceedings, as we provide in this decision, it is most probable that the revenues to the natural gas producers would have been adequate to expand exploration and production activities.

Having concluded that a base rate of return of 15 percent provides a sufficient incentive to attract capital to natural gas exploration and production ventures, it is

necessary to consider the impact of allowing the rate provided for non-associated gas for associated and dissolved gas and for gas formerly sold under expiring contracts where a new contract has been executed. Associated and dissolved gas represents a lower cost product than non-associated gas since it is primarily a by-product of crude oil production. As such its costs are very likely to be considerably less than the cost of new non-associated gas supplies where the gas must bear the entire investment. Allowing the same price for this lower cost product as is allowed for the higher cost non-associated gas increases the overall rate of return on gas related activities while providing an additional incentive for increased oil exploration. The potential magnitude of this allowance may be ascertained when associated and dissolved gas additions have averaged approximately 1.8 Tcf per year for 1966-1972.[71]

[3552]

Renewal contracts qualifying for the national rate[72] provide additional revenues and additional return to natural gas producers selling natural gas in interstate commerce. There are, of course, cases where the cost of continuing to produce additional quantities of gas may be greater than the price allowed by the expired contract or the higher national rate; however, the special relief provisions established in this proceeding[73] and under Section 2.76[74] furnish avenues of

71. Opinion No. 699 at 114, Table 4.

72. The renewal contracts which qualify for the national rate are set forth at 40-44 *infra.*

73. 18 C.F.R. §2.56a(g).

74. 18 C.F.R. §2.76; *Policy With Respect To Sales Where Re-*

relief. In many cases, however, reservoirs continue to produce substantial quantities of gas after the original contract has expired at a cost which is significantly less than the estimated cost of new non-associated gas supplies. Again, the result is incremental return which is an addition to the base rate of return allowed for new gas supplies.

Finally, we note an error in Opinion No. 699 pertaining to the capital structure of a group of petroleum companies. The table in Opinion No. 699 was:

[3553]

*Capital Structure - 1972**

	Million Dollars	Capital Ratios	Costs	Weighted Component
Long-term Debt	$21,858	23.35%	6.25%	1.46
Preferred Stock	404	.43	6.00	.26
Common Equity	71,352	76.22	17.42	13.28
	$93,614	100.00%		15.00%

* Source: Financial Analysis of a Group of Petroleum Companies A Chase Manhattan Bank Study.

The table should have read:

Capital Structure - 1972

	Million Dollars	Capital Ratios	Costs	Weighted Component
Long-term Debt	$21,858	23.35%	6.25%	1.46
Preferred Stock	404	.43	6.00	.03
Common Equity	71,352	76.22	17.73	13.51
	$93,614	100.00%		15.00%

duced Pressures, Need For Reconditioning, Deeper Drilling, Or Other Factors Make Further Production Uneconomical At Existing Prices, Docket No. R-458, 49 F.P.C. 992, as amended, 49 F.P.C. 1325 (1973).

If the cost of long-term debt and preferred stock is increased to 9 percent, the return on common equity becomes 16.87 percent.

b. *The Rate Base*

The main rate base issue is whether the Commission should adopt the principles of "full cost accounting"[75]

[3554]

thereby allowing a return on the dry hole or "unsuccessful well" costs.[76] As previously mentioned,[77] we believe that it is better to adopt a DCF costing formula rather than graft the full cost accounting or return on dry hole cost concepts onto the *Permian* formula.

4. *Summary of Costs and Rate Determination*

The costs derived from the DCF studies range from 47.82 cents per Mcf for the low end of the range to 51.46 cents per Mcf for the high end of the range.[78]

The low end of the range is based upon untrended 1972 drilling costs found in Opinion No. 699 at Appendix C, Schedule No. 1, Sheet 1 of 9, adjusted to reflect a 15% return on investment under a DCF analysis. *See* Appendix C to this opinion.[79]

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75. The parties urging the adoption of a return on dry hole costs include the Producers, the Pennzoil Group, Tenneco Oil Company, The Rodman Corporation, Texasgulf, Inc., UDC, and General Motors.

76. ____F.P.C.____, Opinion No. 699 at 64 n.85.

77. *Supra* at 13-18.

78. An annual escalation of 1.0 cents per Mcf is allowed for in both cases consistent with the escalation provided in Opinion No. 699.

79. These costs were used in Case III of Appendix H to Opinion No. 699 to compute a DCF return of 12.65%.

The high end of the range is based upon trended drilling costs of $29.83 per foot for successful wells and $16.69 per foot for dry holes. The productivity is 485 Mcf per foot based upon our findings in Opinion No. 699 and the discussion of reserve additions and drilling footages *supra* at 17-27.

Based upon the foregoing cost range, we conclude that the rate determined in Opinion No. 699 should be increased from 42¢ per Mcf with escalations of 1.0 cents per Mcf per annum. We find that a reasonable rate may be prescribed ranging from 48 to 52 cents per Mcf and establish a just and reasonable rate of 50 cents per Mcf. This rate is sufficient to allow the recovery of all costs plus a DCF return of 15 percent when all factors are considered.

[3555]

5. *Federal Income Taxes*

The Producers, the Pennzoil Group, The Rodman Corporation, Tenneco Oil Company, and Texasgulf, Inc., all allege that error was committed in the Commission's decision not to include a Federal Income Tax allowance in the national rate established in this proceeding.

We believe that the decision to reserve this issue for individual company proceedings is correct. As we stated in Opinion No. 699,[80] the complex nature of the Federal tax laws negate any simple calculation of a Federal tax liability and require consideration of the producer's tax returns in order to consider the timing relationships be-

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80. ____F.P.C.____, slip opinion at 73-76.

tween investment expenditures, the expensing of intangible drilling costs,[81] and jurisdictional sales.[82]

[3556]

Those parties questioning our treatment of the income tax issue cite the *City of Chicago* decision[83] as requiring the Commission to adopt their procedures for the computation of a tax liability. We do not so read that decision for the quoted language is only a part of the Court's reasoning in rejecting the petitioner's argument that the application of area rates to pipeline production without adjustment for individual pipeline tax liabilities violated the "actual taxes paid" principles.[84] There is no reasoning in that discussion which compels the Commission to adopt the income tax computations set forth by participants to this proceeding just as the Court found no requirement that the Commission consider individual pipeline tax liabilities in pricing pipeline owned production.

6. *Gathering Allowances*

In Opinion No. 699 (93-94), we provided for gathering allowances in the Hugoton-Anadarko, Permian Basin, and Rocky Mountain Areas. The Producers urge that we have erred in providing these gathering allowances by (i) reducing the gathering allowance for the Permian Basin from the 1.5 cents per Mcf provided in Opinion No. 662

81. Int. Rev. Code of 1954, §263(c); Treas. Regs. §1.612-4.

82. Such an investigation would be concerned solely with expenses, deductions, and revenues associated with and incurred or generated in connection with jurisdictional sales. ____F.P.C.____, Opinion No. 699 at 74.

83. *City of Chicago v. FPC*, 458 F.2d 731 at 756 (1971), *cert. denied*, 405 U.S. 1074 (1972).

84. *See* 458 F.2d 731 at 754-757.

(50 F.P.C. 462 (1973)) to 1.0 cents per Mcf and (ii) failing to recognize the gathering allowances provided in the Appalachian-Illinois Basin, Other Southwest, Southern Louisiana, and Texas Gulf Coast Areas. The Producers further urge that the 1.0 cents per Mcf gathering allowance prescribed for the "Other Fields" of the Hugoton-Anadarko Area and the Rocky Mountain Area be increased to 1.5 cents per Mcf as provided in *Permian II*. We agree that the first two points raised by the Producers dictate corrective action; however, there is no

[3557]

data or evidence in this record which dictate an increase in the previously determined gathering allowances for the "other Fields" of the Hugoton-Anadarko Area and the Rocky Mountain Area.

The reduction in the gathering allowance for the Permian Basin from 1.5 cents per Mcf to 1.0 cents per Mcf was an inadvertent error and section 2.56(h)(4) will be revised accordingly.

Unlike the gathering allowances for the Hugoton-Anadarko, Permian Basin, and Rocky Mountain Areas which were stated separately, the gathering allowances for the Other Southwest, Southern Louisiana, and Texas Gulf Coast Areas were made a part of the base rates. Furthermore, a deduction equal to the applicable gathering allowance was provided for if the gas was delivered to the purchaser closer to the wellhead than a central point in the field, the tailgate of a processing plant, an offshore platform, or a point on the purchaser's pipeline in the Other Southwest,[85] Southern Louisiana,[86] and Texas Gulf Coast[87]

85. 46 F.P.C. 900, 919, 924 (1971).

86. 46 F.P.C. 86, 132, 143 (1971).

87. 45 F.P.C. 674, 704, 719 (1971).

Areas. Thus, in these areas we will prescribe gathering allowances to be added to the base national rate only if deliveries are made no closer to the wellhead than the points described above. The amount of the gathering allowance provided for these areas will be the amount prescribed in the applicable area rate opinion.

The gathering allowance for the Appalachian-Illinois Basin Area was included in the base area rates and made

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applicable to all sales.[88] The same treatment for gathering in the Appalachian-Illinois Basin Areas will be provided in this proceeding.

The producers also allege that the gathering allowances for the "Other Fields" of the Hugoton-Anadarko Area and the Rocky Mountain Area should be increased from 1.0 cents per Mcf to 1.5 cents per Mcf because of "increasing costs, necessity for additional compression on older systems and inflation itself." We have exhaustively reviewed the record of this proceeding for evidence which would support such a claim, and we find none. In such cases, the mere allegations of counsel are not sufficient to support the increase and the claim is accordingly rejected.

7. *Btu Adjustment*

The Producers and United Gas Pipe Line Company (United) have questioned the procedures for computing the Btu adjustment that were promulgated in Opinion No. 699.

88. 44 F.P.C. 1112, 1122-1123 (1970). This allowance applies to all sales whether or not the gas is gathered.

United objects to the computation of the Btu adjustment after the applicable severance or production tax has been added to the base national rate because it must now reimburse 100 percent of any such taxes rather than 87.5 percent as required by this Commission's orders for the Other Southwest, Southern Louisiana, and Texas Gulf Coast Areas and because the producers have no incentive to object to new increases in such taxes.

We believe that United's position should be rejected. There is no rational reason why natural gas producers who elect to sell their gas in interstate commerce pursuant to Opinion No. 699, as amended by this Opinion, should be

[3559]

penalized because a state legislature determines that the best interest of the state dictates an increase in that state's production or severance tax. In past opinions, natural gas producers were allowed to pass on a fraction of the increased taxes, generally 87.5 percent, and bear the remainder. While there may be a sustainable basis for such a practice in the past, we are unable to conclude that natural gas producers should not be permitted to pass on the total amount of such increases. The Btu adjustment authorized in this proceeding is consistent with the past practices of this commission which indicate that the base rate is to be adjusted for production or severance taxes before the selling price is adjusted for Btu content.

Both United and the Producers seek clarification of the basis upon which the Btu adjustment is to be made. United requests the Commission to clarify whether "the Btu will be measured on a 'saturated' or 'dry' basis depending upon

the terms of each individual contract." The Producers argue that the heating content (Btu) "of the gas should be adjusted for the water vapor content in the gas as it is delivered." In *Texaco, Inc.*, 33 F.P.C. 1228 (1965), the Commission determined that Btu adjustments should be made on a saturated basis. 33 F.P.C. 1228 at 1236-1237. This is the basis which was utilized in the area rate proceedings, and it is the basis that will be adopted in this proceeding. Section 2.56(h)(2) will be modified accordingly to reflect Ordering Paragraph (D) of Opinion No. 464. 33 F.P.C. 1228 at 1238.

B. *Scope of the Order.*

A number of parties have questioned the scope of the order in this proceeding with respect to the eligibility requirements for the three classes of natural gas sales which the Commission has determined qualify for the rate prescribed by this decision. In Opinion No. 699-A,[89]

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the language of Opinion No. 699[90] and Section 2.56(h)(1) was amended to provide the following eligibility requirements for those qualifying classes of gas supplies other than gas supplies which qualify under a "wells commenced" standard:

> (2) sales initiated on or after January 1, 1973 for the sale of natural gas in interstate commerce where such gas has not previously been sold in interstate commerce except pursuant to the provisions of 18 C.F.R. §§2.68, 2.70, 157.22, or 157.29, or (3) sales

89. ____F.P.C.____ (August 2, 1974).

90. ____F.P.C.____, ____, Opinion No. 699 at 1.

> made pursuant to contracts executed on or after January 1, 1973, where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which [have] expired by their own terms.

Most of the questions concerning the scope of Opinion 699 pertain to the interrelationship between Opinion 699 and Opinion 639.[91] Other questions relate to sales commenced under the optional procedure pursuant to 18 C.F.R. 2.75(n) where the optional certificate is not accepted or issued and to which wells commenced on or after January 1, 1973, qualify for the national rate. Pipeline production and newly discovered reservoirs are discussed *infra* at 46-50.

1. *Renewal Contracts.*

By Opinion No. 639, *supra* n.91, the Commission announced its policy of eliminating vintaging by contract date through the vehicle of allowing the renewal contract to receive the new gas rate upon expiration of the term of the previous contract pursuant to the provisions of the prior contract. The Commission has applied this policy in several situations as to the timing of the renewal contract and the expiration of the prior contract as the Producers point out.

Opinion 699 allowed the national rate only to those situations where the prior contract expired on or after

[3561]

January 1, 1973, and the renewal contract was executed on or after that same date. Opinion No. 699-A, *supra,*

91. 48 F.P.C. 1299 (1972).

amended this language to include all renewal contracts executed on or after January 1, 1973, regardless of the date of expiration of the term of the primary contract.

The amended language of Opinion No. 699-A meets one of the two situations advanced by the Producers as not being covered by Opinion No. 699.[92] However, the other situation where a contract is entered into prior to the cutoff date and prior to the expiration of the term of the contract does not fall within the language of Opinion No. 699. We believe that renewal contracts falling within this classification should be allowed the national rate after the expiration of the term of the previous contract and not before that date. *Mobil Oil Corp. (Operator), et al.*, 49 F.P.C. 239 (1973).

In making such modifications, we shall continue to require that the renewal contract be executed on or after January 1, 1973, or, in the alternative, that the term of the primary contract has expired on or after

[3562]

that date, whether or not the renewal contract was executed before that date.[93] While such requirements may

92. These two situations were (a) where the term of the prior contract expired prior to January 1, 1973, and a new contract was executed on or after that date and (b) where the term of the prior contract expired on or after January 1, 1973, and a renewal contract was executed prior to that date. The Commission held that the new gas rate applied to such sales in *Southern Union Production Company*, 50 F.P.C. 217 (1973), and *Mobil Oil Corporation (Operator), et al.*, 49 F.P.C. 239 (1973), respectively. In *Mobil Oil Corporation (Operator), et al.*, 49 F.P.C. at 239, we held the new price would not become effective until the term of the prior contract expired.

93. In Opinion No. 639, we spoke in terms of the prior contracts being those executed prior to October 8, 1969, and renewal contracts as those contracts which replace the pre-October 8, 1969, contracts.

not extend the national rate to all sales that come within the literal terms of Opinion No. 639, they are reasonable limitations upon the scope of the national rate.

Superior Oil Company's suggestion that the national rate be allowed for sales of natural gas where the term of the prior contract has expired and the seller and purchaser have been unable to agree upon a renewal contract must be rejected. The principles of vintaging expressed in Opinion No. 639 as adopted in Opinion No. 699 presumes that purchaser and seller of gas which is the subject of an expired contract will execute a renewal contract that is beneficial to both.

The automatic allowance of the national rate upon expiration of the formerly effective contract would release the seller from any obligation to bargain in good faith with the purchaser for a new contract, and such a situation we believe to be contrary to the public interest.[94] In many cases, the purchasing pipeline may desire a *quid pro quo* from the selling producer in the form of additional

[3563]

acreage dedication, exploration and development activity on the previously dedicated acreage, or other similar activities that could result in the dedication of additional new gas supplies to the interstate market. Such concessions by

October 7, 1969, was the division date for vintaging purposes in the Appalachian and Illinois Basin areas. 49 F.P.C. 1299 at 1310. Thus, since we establish a new vintaging date of January 1, 1973, in this proceeding, it follows that this date should be utilized in a rational manner to determine which renewal contracts are eligible for the national rate.

94. Likewise, there is an obligation upon the purchaser of such gas to bargain in good faith with the seller to formulate a renewal contract.

the seller will certainly not be made if the price is allowed to increase to the national rate automatically without the requirement of a renewal contract. Since such concessions are in the public interest because of the need for additional gas supplies which can be dedicated to interstate pipelines, it would be untenable to force the purchasing pipeline to pay the increased rate without the opportunity to obtain additional benefits for itself and its customers.

Finally, we find no merit to Superior's contention, made at the oral argument in this proceeding, that the requirement of a renewal contract violates section 4(b) of the Natural Gas Act.[95] No evidence was made a part of the record of this proceeding which would support such an argument, and, in the absence of such evidence, we are constrained to reject the argument. In so disposing of Superior's argument, we do not intend to imply that there may not be situations where the refusal of the purchaser to bargain in good faith for a renewal contract would not provide a basis for Commission action to remedy the situation.

[3564]

On September 6, 1974, Austral Oil Company Incorporated (Austral) filed a motion for reconsideration of Opinion No. 699[96] and 699-A[97] and proposed that the

95. Section 4(b) provides:

> No natural gas company shall . . . (1) make or grant any undue preference or advantage . . . or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, . . . or any other respect, either as between localities or as between classes of service.

52 Stat. 821, 822 (1938); 15 U.S.C. §717c(6) (1970).

96. ____F.P.C.____.

97. ____F.P.C.____.

promulgated regulations be amended to provide that deliveries which have been made for a period of twenty years or more under a contract for the life of the lease are entitled to the national rate.[98] Austral did not raise this issue before Opinion No. 699 was issued by filing comments and its motion presents no evidence which would make our consideration of the issue appropriate upon rehearing. Accordingly, Austral's motion is denied without prejudice to Austral submitting such comments on the issue as it desires to enter into the record of the proceeding instituted today to establish rates for the 1975-1976 biennium.[99]

[3565]

2. *Optional Procedure Deliveries.*

A number of parties have requested that we include sales commenced pursuant to Section 2.75n[100] of the optional procedure[101] with sales formerly made pursuant to the provisions of the emergency sales and limited term

98. This filing was not made within 30 days of either Opinion No. 699 or 699-A as required by statute, and it must, therefore be treated as a motion for reconsideration rather than an application for rehearing. *See Appalachian Power Company,* Project No. 2317, Opinion No. 698-A at 2-5. ____F.P.C.____ (1974).

99. *See National Rates For Jurisdictional Sales Of Natural Gas Dedicated To Interstate Commerce On Or After January 1, 1973, For The Period January 1, 1975, To December 31, 1976,* Docket No. RM75-14, "Order Instituting National Rate Proceeding," ____ F.P.C.____ (December 4, 1974).

100. 18 C.F.R. §2.75n.

101. *Optional Procedure For Certificating New Producer Sales Of Natural Gas,* 48 F.P.C. 218, *amended* and *reh. denied,* 48 F.P.C. 477, *reh. denied,* 48 F.P.C. 1002 (1972), *affirmed, John E. Moss, et al. v. FPC,* Nos. 72-1837, D.C. Cir., August 15, 1974 (Reversed as to pregranted abandonment, section 2.75e).

certification procedures[102] as qualifying for the national rate. This position has merit, and we shall adopt it on the express condition that no certificate has been issued under the optional procedure for the subject sale.

The caveat which we adopt is necessary to assure the integrity of the national rate structure and the optional procedure as separate components of a total rate design. The caveat guarantees that a producer who may have been issued an optional certificate at a rate which is lower than the national rate will not later seek a new certificate at the national rate because it provides greater benefits than the rate under the optional certificate.

[3566]

3. *Newly Discovered Reservoirs in Committed Acreage.*

In Opinion No. 567,[103] the Commission determined that newly discovered reservoirs located on acreage previously dedicated to interstate commerce would be entitled to the price which otherwise be applicable to a contract dated as of the date of discovery except for the fact that the subject acreage had been dedicated under a contract in an earlier vintaging period. The Producers contend that we clarify Opinion No. 699 "by providing that Section 2.56 . . . be appropriately amended to provide for the application and interaction of the principles of Opinion 567 and that of the National Rate. . . ." We believe that this contention is well taken and it will be adopted as a modification of Section 2.56a (formerly Section 2.56(h)).

102. 18 C.F.R. §§2.68, 2.70, 157.22, and 157.29.

103. *Hugoton-Anadarko Area Rate Proceeding (Committed Acreage), et al.,* Docket No. AR64-1 (Severed Issue), *et al.,* 42 F.P.C. 726 *reh. denied,* 42 F.P.C. 1062 (1969), clarified, 43 F.P.C. 222 (1970).

We shall provide that reservoirs, discovered on or after January 1, 1973, as the result of a well commenced on or after January 1, 1973, on acreage dedicated to interstate commerce in such a manner that the sale would not otherwise come within the provisions of subsection 2.56a (a)(1), shall be entitled to the rate determined in this proceeding. In most situations, we believe that reservoirs discovered on or after January 1, 1973, on acreage committed under acreage dedications to interstate commerce prior to January 1, 1973, would come within the provisions of the first two classes of sales enumerated under Section 2.56a(a)(1). There may, however, be cases where such would not be the case, and we will accordingly provide that these reservoirs will be entitled to the rate prescribed herein.

[3567]

The producer seeking the national rate for production from newly discovered reservoirs on committed acreage shall make the filings required by 18 C.F.R. §2.56(f)(2). This subsection has been incorporated as part of the national rate structure in Section 2.56a.

4. *Pipeline Production*

By Opinion No. 568,[104] the Commission determined that natural gas produced from leases acquired after October 7, 1969, by a pipeline or a pipeline affiliate would be priced at the area rate applicable to gas of the vintage which corresponds to the date that the first well on the lease is completed.[105] We believe that the General Policy

104. *Pipeline Production Area Rate Proceeding (Phase I),* 42 F.P.C. 738, *as amended,* 42 F.P.C. 1089 (1972), *affirmed, City of Chicago v. F.P.C.,* 147 U.S. App. D.C. 312, 45[illegible] F.2d 731 (D.C. Cir. 1971), *cert. denied,* 405 U.S. 1074 (1972).

105. 42 F.P.C. 738 at 754, 18 C.F.R. §2.66(a).

Statement relating to that decision should be amended by adding a new subsection (c) which will provide that natural gas which comes within one of the classes enumerated in new Section 2.56a(a)(2) shall be entitled to the rate set forth in that section regardless of the date the lease was acquired by a pipeline or pipeline affiliate.

During oral argument, it was noted that the language of Section 2.66(a) may pose a vintaging problem for new

[3568]

drilling efforts by pipelines on post-October 7, 1969 leases.[106] While the vintaging policy announced in Opinion No. 567 is not referred to in Section 2.66, it is referred to in the text of Opinion No. 568,[107] and we believe that it should be applied to leases owned by pipelines and pipeline affiliates. Thus, new reservoirs discovered on such leases will be entitled to the national rate applicable to wells commenced and new dedications to interstate commerce of the date of discovery.

In applying the uniform national rate to all qualifying production from leases owned by pipelines or pipeline affiliates, regardless of the date of acquisition of the lease, we are not unmindful of the fact that Opinion No. 568 reserves the rate treatment of pipeline production from leases acquired prior to October 8, 1969, to Phase II of the *Pipeline Production Area Rate Proceeding,*[108] and

106. The specific language reads:

> . . . gas . . . will be priced . . . at the just and reasonable area rate applicable to gas of a vintage corresponding to the date of completion of the first well on the lease. . . .

18 C.F.R. §2.66(a).

107. 42 F.P.C. 738 at 752.

108. 35 F.P.C. 497 (1966). *See* also *Area Rate Proceeding, et al. (Hugoton-Anadarko Area),* 31 F.P.C. 1595 (1964).

that Phase II was terminated by our order of June 14, 1972, reserving the appropriate rate treatment for such leases to company by company rate proceedings.[109]

[3569]

In the order terminating Phase II, the Commission stated:

> We believe the search for consumer protection through proper incentives and proper price can best be achieved by consideration of individual pipeline production and cost patterns, and company by company determination of pricing for production of leases acquired prior to October 7, 1969.

47 F.P.C. 1523. At the time these principles were announced, the applicable area rate was dependent upon date of contract dedicating the production to the interstate market[110] rather than date of well commencement as established in this proceeding. The change to vintaging by a well commencement date rather than date of contract should be applied to pipelines and pipeline affiliates as well as producers. There is no difference between a well commenced on or after January 1, 1973, by a pipeline or pipeline affiliate on a lease acquired prior to October 7, 1969, and a similar well commenced on a lease acquired after that date just as there is no difference between a well commenced by a pipeline or pipeline affiliate and a similar well commenced by a producer. Since it is the time at which a well is drilled that ultimately results in the great-

109. 47 F.P.C. 1523 (1972).

110. Newly discovered reservoirs located on previously committed acreage were subject to the price determined by date of discovery rather than date of contract. *See* n. 103, *supra.*

er portion of the cost of the gas supply rather than the costs incurred at the time the lease was acquired, the artificial distinction of lease acquisition date promulgated in Opinion No. 568 should be eliminated from the national rate structure. The existing natural gas shortage requires the best efforts of all persons whether producer, pipeline, or pipeline affiliate to explore for and develop new supplies of gas to satisfy existing unfullfilled demands. These best efforts should not be hindered simply because of the date the

[3570]

lease was acquired,[111] and it is, therefore, in the public interest to allow the national rate for pipeline or pipeline affiliate production which qualifies under Section 2.56a(a)(2)[112] regardless of the date on which the subject lease was acquired.

C. *The Biennial Review*

As a result of our further consideration of the biennial review procedures set forth in Opinion No. 699[113] and the comments with respect to that portion of the opinion filed in petitions for rehearing, we have concluded that those portions of Opinion No. 699 must be modified to

111. Whether production dedicated to the interstate market prior to January 1, 1973, from pipeline or pipeline affiliate leases acquired on or before October 7, 1969, should receive the rate ultimately determined for pre-January 1, 1973, gas supplies is a matter to be resolved in Docket No. R-478.

112. See *infra* 75-76, Ordering Paragraph (A). We believe that this clarification answers the questions posed by the New Mexico Commission since gas produced from post-December 31 1972, wells will qualify for the national rate whether drilled by a pipeline or a producer.

113. ____F.P.C.____, Opinion No. 699 at 101-102.

permit all gas which initially qualifies for the rate prescribed by Opinion No. 699 to be priced at the rate established for each succeeeding period.

The biennial review procedures established by Opinion No. 699 will result in the promulgation of numerous vintages of gas each with a locked-in rate subject only to annual escalations. These pricing policies, if implemented, could discourage the dedication of new gas supplies to the interstate market and cause further increases in the curtailment of service by most of the major interstate pipelines.[114]

[3571]

Such results are clearly contrary to the Commission's responsibility under the Natural Gas Act to assure the maintenance of adequate supplies of natural gas at the lowest reasonable price.[115] The continued decline in discoveries of new gas supplies and increased curtailment by the pipelines will increase the costs paid by the consumer for the gas itself at the wellhead and for the transportation service performed by the pipeline. These increases will ultimately produce prices that are not just and reasonable, but excessive, and service which is totally inadequate.

We are of the opinion, however, that adjusting the rate established in Opinion No. 699 to the rate levels established in succeeding biennial reviews will encourage the

114. *See* Opinion No. 699, ____F.P.C.____, slip opinion at 31-35.

115. *Mobil Oil Corp. v. F.P.C.*, 42 U.S.L.W. 4842 (U.S. June 10, 1974). *See Atlantic Refining Co., et al. v. Public Service Commission of New York*, 360 U.S. 378 at 388 (1959), citing §7(c) of the Natural Gas Act as enacted, 52 Stat. 825. "The 1942 amendments to §7, 57 Stat. 83, were not intended to change this declaration of purposes." 360 U.S. 378, 388, n. 7.

dedication of additional gas supplies to the interstate market at the lowest total cost to the consumer while protecting the financial integrity of the producer. Whether these adjustments will be upward or downward will, of course, depend upon whether costs and the other pertinent rate design factors increase or decrease.[116] It is precisely

[3572]

these variables that will be considered in the biennial reviews to determine rates for future periods, and these continuing reviews will allow the Commission to monitor changes in the economy which have a bearing upon the price of gas and the need for capital to finance the necessary exploration, development, and production activities. With the adjustment of all new (post-December 31, 1972) dedications of gas to the same rate, the burden of financing new gas supplies can be distributed between old and new customers and between historic and future demand.

The adjustment of all rates for post-December 31, 1972, dedications to the newly established rate will also over an extended period of time result in a uniform base price for gas sold in interstate commerce, which equates to the cost of replacing the unit of gas consumed. This uniform price will constitute a recognition of the fact that gas is a consumable, irreplaceable commodity and not a

116. The evidence of record in this proceeding indicates that drilling and other costs have trended upward since the early 1960's and that productivity has risen and fallen during the same period. The increasing severe inflation in the economy all but guarantees that costs and, therefore, rates will not decrease in the near future. More importantly, this inflation will require a continuing review not only of the cost factors, but also the rate of return allowed as just and reasonable.

service which can be renewed by man.[117] Thus, there is no rational basis for setting differing price levels based upon date of discovery, lease acquisition, contract, or well commencement or completion over an extended period of time.[118] Our

[3573]

application of the principles enunciated in Opinion No. 639 in this proceeding permits the rate allowed for gas sold pursuant to older contracts to rise as those contracts terminate by their own terms adding to the revenues and, in turn, capital available to those entities which will explore for and develop new natural gas supplies for the interstate market.

As we previously noted, the magnitude of the drilling effort that will be required to elicit the supply of gas necessary to fullfill reasonable future demands[119] calls for massive capital commitments.[120] Much of the capital for exploration, development, and production comes from

117. *See F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 at 647 (1944), (Jackson, J., concurring); *Placid Oil Co. v. F.P.C.*, 483 F.2d 880 (1973).

118. For the immediate future, we believe the distinction drawn between gas which qualifies for the rate established in this proceeding and the rate which qualifies under Docket No. R-478 should be maintained to avoid potentially severe and harmful economic dislocations due to significantly increased rates. These disclocations will be slowly eliminated by the vintaging policies adopted in this opinion and Opinion No. 639. *Area Rates for the Appalachian and Illinois Basin Areas*, 48 F.P.C. 1299 at 1309-1310 (1972), *affirmed sub nom., Shell Oil Co., et al. v. F.P.C.*, 491 F.2d 82 (5th Cir. 1974).

119. ____F.P.C.____, Opinion No. 699 at 22-24.

120. The total amount of capital required will be further increased by the continued rise in costs which may be expected for several years into the future.

gas production revenues, and, therefore, we find it appropriate to adjust the rate determined in this proceeding to whatever level the biennial review demonstrates to be just and reasonable as one means of generating the necessary capital. Because we fully expect future rates to be higher, the adjustment of the rates established in this opinion to those higher levels which are above the costs found to be reasonable in this opinion will generate additional revenues above costs which can be reinvested to expand exploration and production activities.[121] Without such increases in the rate allowed for post-December 31, 1972, gas supplies, we do not believe that it will be possible for natural gas producers to generate the internal funds necessary to undertake the massive expansions of present exploration and development programs which we find to be essential if a level of annual reserve additions approximating

[3574]

37 trillion cubic feet is to be remotely approached and sustained.[122]

D. *The Impact on the Consumer*

In prescribing a just and reasonable national base rate of 50 cents per Mcf, we have carefully considered the

121. Rates will not be allowed to increase indefinitely without some discernible increase in the level of monies committed to exploration and development programs and the volumes of new gas supplies dedicated to interstate pipelines under long-term contracts.

122. Whether such a level of physical findings can be achieved and sustained is a question that only experience can provide an answer for; however, it is certain that this level will never be attained unless the funds are available to finance exploration, drilling, developmental, and production activities. *See* Opinion No. 699 at 23.

impact of this rate upon the cost paid by the consumer for natural gas. In order to evaluate the impact of this rate upon the price paid by the consumer, we have estimated the potential impact on the price charged the residential gas consumer in four widely dispersed metropolitan areas of the United States.

Assumptions must be made in order to estimate the potential impact of increased prices for new supplies of natural gas. In the following table, it is assumed that new gas supplies including supplies sold pursuant to renegotiated contracts will account for five (5) percent of the supplies delivered in the first year and will increase by an additional 5 percent of the total volumes delivered each following year. It is further assumed that the volumes delivered to these four markets will remain constant over the next five years. To the extent that increasing curtailments reduce the volumes of gas available at the prices paid during the calendar year 1973, the estimated increases shown in Part IV of the table will be somewhat greater. The prices shown in the table reflect the annual escalation of 1.0 cents per Mcf, a seven percent production tax, a Btu content of 1,030 Btu per cubic foot, and a gathering allowance of 1.0 cents per Mcf. The prices are computed as provided in Appendix D to Opinion No. 699, ____ F.P.C. ____ at ____. The prices do not reflect any adjustments that may result from the biennial review prescribed by this opinion.

Potential Impact
Of 50 Cent Base Rate, as Adjusted, on Residential Bills in Selected Markets
Assuming 5% Increments

Line No.		Classification	Residental Market Areas: Washington D.C.	Boston Mass.	Chicago Ill.	Los Angeles Cal.
	I.	Average Cost of Natural Gas Service for Calendar 1973 in $/Mcf 1/				
1.			1.67	2.37	1.20	1.16
	II.	Increase in the Cost of Natural Gas Assuming 5% Increments of Gas Purchased at Base Rate, as adj. 2/				
2.		a. 5% (1974) 56.38c	.0169	.0169	.0169	.0169
3.		b. 10% (1975) 57.48c	.0349	.0349	.0349	.0349
4.		c. 15% (1976) 58.59c	.0540	.0540	.0540	.0540
5.		d. 20% (1977) 59.70c	.0742	.0742	.0742	.0742
6.		e. 25% (1978) 60.81c	.0955	.0955	.0955	.0955
	III.	Adjusted Average Cost of Natural Gas $/Mcf				
7.		a. 1974	1.6869	2.3869	1.2169	1.1769
8.		b. 1975	1.7049	2.4049	1.2349	1.1949
9.		c. 1976	1.7240	2.4240	1.2540	1.2140
10.		d. 1977	1.7442	2.4442	1.2742	1.2342
11.		e. 1978	1.7655	2.4655	1.2955	1.2555
	IV.	Percent Change as Result of 50¢ Price for Each Increment %				
12.		a. 5%	1.01	.71	1.41	1.46
13.		b. 10%	2.09	1.47	2.91	3.01
14.		c. 15%	3.23	2.28	4.50	4.66
15.		d. 20%	4.44	3.13	6.18	6.40
16.		e. 25%	5.72	4.03	7.96	8.23

1/ Source: AGA's Gas Facts for 1973.

2/ Volumes based upon Form 11 data for 12 months ending December 1973 and assumes constant level of total volumes.

[3576]

If new supplies at the national rate constitute a 10 percent increment of the total supplies delivered in the first year and an additional 10 percent increment each following year, the increase attributable to the wellhead price of gas paid by consumers in residential market areas would be 19.1 cents per Mcf by 1978. This would result, by 1978, in a total price per Mcf of $1.8610 in Washington, D.C., $2.5610 in Boston Mass., $1.3910 in Chicago, Ill., and $1.3510 in Los Angeles, Calif. The precent changes in the prices paid by residential consumers in these same markets would be:

Year	Washington D. C.	Boston Mass.	Chicago Ill.	Los Angeles Calif.
1974	2.02	1.42	2.82	2.92
1978	11.44	8.06	15.92	16.46

Furthermore, 50 percent of the total volumes of gas being sold in interstate commerce will be priced at the national rate by 1978 if the annual increments are 10 percent.

Referring to the table and accompanying text, it appears that the increases in the average residential price will range between 0.71 percent and 1.46 percent in the first year and between 4.03 percent and 8.23 percent after five years if total volumes of gas priced at the national rate account for an annual increment of 5 percent of the total volumes delivered that year. If the annual increment is 10 percent then the increases will range from 1.42 percent to 2.92 percent for the first year and from 8.06 percent to 16.46 percent after five years. The increases will tend to be smaller, percentage-wise, as the distance from the major producing areas to the consumer market in-

creases, but the dollar impact will be determined by the relative importance

[3577]

of new gas supplies in each market's total gas supply. In addition, of course, there will be an indirect impact upon consumers to the extent that increased gas prices paid by commercial and industrial customers are passed on in the form of higher prices for goods and services. As noted below, however, the increased availability of gas supplies at the national rate will, in many instances, enable commercial and industrial customers to continue their use of gas rather than converting to a higher cost alternative fuel. In these cases, the increased price for gas might well prove to be deflationary rather than inflationary.

In evaluating the overall public interest, we must consider the benefits to the consumer of an incremental supply of gas to provide reliable gas service compared to the consumer detriment if natural gas supply is reduced. The increased consumer cost attributable to higher wellhead gas prices is more than counterbalanced by the more probable assurance of continued service. It should be noted that even with the increased cost of gas to the consumer as a result of this decision the price paid for gas will remain less than the price of alternate fuels in these same markets. These customers will, of course, be confronted with even higher energy costs when demand is referred to other higher-priced alternate fuels because an adequate and reliable supply of gas is not available. We believe that it is in the best interest of the American consumer to pay the higher price for gas which is necessary to induce expanded exploration and production efforts than it is for that same consumer to pay even higher prices for

other fuels, if substitutable. To the extent that incremental supplies of gas will be made available to consumers at less cost than alternate fuels, inflationary pressures will be diminished and we will more effectively allocate and utilize our energy resources.

[3578]

Since more than 50% of the energy fueling our industrial economy is natural gas,[123] which in many applications cannot be efficiently displaced by other fuels, the augmentation of our natural gas supply will contribute to our productivity, will reduce unemployment, and will assist in maintaining a viable economy.[124]

Future supplies of gas required to replace the volumes being consumed today as well as increase the deliverable volumes to meet anticipated future demands will come from greater depths onshore and from both greater well depths and water depths offshore. These supplies will not be discovered and produced at yesterday's prices so it is important that we establish a price that will encourage the development of those higher cost supplies. The consumer must pay this price if he is to obtain the volumes of gas required to satisfy his demands for a reliable, non-polluting energy source.

In establishing a base rate of 50¢ per Mcf as the national rate and reinstating emergency and limited-term procedures in Opinion No. 699-B, we are carrying out our

123. Federal Power Commission, Natural Gas Survey, Volume I, Chapter 6, "Total Energy Supply and Demand," at pages 40 and 93 (Preliminary Draft).

124. Employment Act of 1946, 60 Stat. 23 (1946), 15 U.S.C. §1021 (1970).

responsibility as a Commission to see that consumers receive adequate and reliable gas service at reasonable prices. In *Hope*[125] the Supreme Court expressed the

[3579]

essential doctrines stating that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks,"[126] and that the Natural Gas Act was "to protect consumers against exploitation at the hands of natural gas companies."[127]

III

DEEPER DRILLING AND DEEPER OFFSHORE WATER DEPTHS

The Producers and GHK Company and Gasanadarko, Ldt., object to the Commission's failure to provide an additional allowance for deeper drilling efforts and all drilling efforts in deeper offshore water depths. With one exception, these objections are fully answered in Opinion No. 699.[128]

There remains the question of how prospective drilling efforts which will explore depths greater than 15,000 feet below the surface and which will take place in water depths greater than 250 feet may be certificated so as to provide

125. *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

126. 320 U.S. at 603.

127. 320 U.S. at 610.

128. The Producers' request for clarification of section 2.56(h)(6)(ii) is noted and section 2.56a(g)(2) [formerly 2.56(h)(6)(ii)] has been amended to reflect the language of Opinion No. 699 at 132-133.

[3580]

finance the drilling effort.[129] Such ventures may be certificated under the optional procedure.[130] This clarification will remove any uncertainty that may have been caused by the *Continental* order.

It is our intention to initiate the proceedings required to determine the appropriate allowances for drilling efforts to depths greater than 15,000 feet and all drilling efforts in water depths greater than 250 feet as part of the biennial review proceedings that have been initiated in Docket No. RM75-14, which is being issued concurrently with this opinion. This will avoid a proliferation of separate proceedings pertaining to similar issues.

IV

CONTINGENT ESCALATIONS AND REFUND CREDITS

The Producers and others argue that the Commission has violated the Natural Gas Act by imposing a reparations order and destroyed the prior area rate opinions in ordering that reserves dedicated pursuant to Opinion No. 699 may not also qualify to discharge refund obligations

[3581]

or trigger contingent escalations. *See* Opinion No. 699 at

129. In *Continental Oil Company, et al.*, Docket Nos. CI74-526, *et al.*, ____F.P.C.____ (July 25, 1974), we held that prospective drilling efforts do not qualify for special relief under the various area rate opinions.

130. 18 C.F.R. §2.75; *Optional Procedure For Certificating New Producer Sales Of Natural Gas*, Docket No. 441, Order No. 455, 48 F.P.C. 218 (1972), as amended by Order No. 455-A, 48 F.P.C. 477 (1972), *affirmed sub nom. John E. Moss, et al. v. FPC*, Nos. 72-1837, *et al.* (D.C. Cir. August 15, 1974).

99-100, 104-105, and section 2.56(h)(ii) [now section 2.56a(i)]. The Producers argue that these incentive provisions were part of the flowing gas rate which is not under consideration in this proceeding and not part of the new gas rate.

These arguments misconstrue the rationale underlying the adoption of these incentive provisions. The refund credit and contingent escalation provisions were adopted in four area rate cases[131] as part of an overall rate structure designed to elicit new supplies of gas for the interstate market. As such they were components in a total rate design which included a determination of both a new gas rate and a flowing gas rate.[132] These rates were balanced with the incentive provisions to insure that new supplies of gas would be available to the consumer at the lowest reasonable price.

In this proceeding, we have established a uniform national rate for post-December 31, 1972 dedications to the interstate market which is designed to elicit new supplies of gas to the interstate market. This rate structure was not contemplated when the earlier area rate

[3582]

opinions were adopted,[133] and it is not reasonable to allow

131. *See* Opinion No. 699 at 99 n. 133, _____F.P.C._____.

132. In all these cases, except *Permian II,* the rate structure also included a moratorium on the filing of rate increases above the established ceilings which expire on January 1, 1976, in the Texas Gulf Coast Area (18 C.F.R. §154.109(a)), July 1, 1976, in the Other Southwest Area (18 C.F.R. §154.109a(a)), and on January 1, 1976, for flowing gas and on January 1, 1977, for new gas in the Southern Louisiana Area (18 C.F.R. §154.105(a)).

133. Our decision in *Permian II,* 50 F.P.C. 390 (1973), was rendered after this proceeding had been initiated but prior to the time

new dedications of gas to the interstate market to receive the price allowed by this decision and, at the same time, discharge refund obligations or trigger escalation provisions pursuant to other opinions of this Commission. We realize that it would be highly advantageous to many natural gas producers to sell new gas supplies at the national rate and have those same volumes discharge existing refunds or trigger contingent escalations, but we find nothing which would indicate that it is in the public interest to allow natural gas producers the benefits of the area rate opinions while avoiding the burdens of those opinions. The allowance of rates prescribed in this opinion plus either the contingent escalation or the refund credit for new gas supplies would constitute an apostasy of the Commission's area rate opinions which adopted the contingent escalations and refund credits as part of a rate structure which included the then prevailing area rates for flowing gas and new gas. See *Mobil Oil Corp. v. F.P.C.,* 42 U.S.L.W. 4842 (U.S. June 10, 1974) (slip opinion at 11-13 and 34-39).

[3583]

As we previously noted in this opinion and in Opinion No. 699, the refund credit and contingent escalation provisions of the area rate opinions with the exception of *Permian II* (Opinion No. 662) were coupled with ceiling rates and moratoria on the filing of rate increases above those ceilings. These factors clearly indicate that the re-

that the rate design set forth in Opinion No. 699 and this opinion was formulated. Since it was desirable to establish rates for the Permian Basin Area rather than defer any action until a decision was finally rendered in this proceeding, that area rate opinion followed our other recent area rate opinions in providing for refund credits and contingent escalations.

fund credits and contingent escalations were intended to be applicable only to those gas supplies that were dedicated to interstate commerce at the ceiling rates prescribed in those opinions. That policy is still valid even though we have established new rates for post-December 31, 1972, dedications of gas to interstate commerce in this proceeding and have pending in Docket No. R-478 a review of the rates for pre-January 1, 1973, dedications.[134] Thus, we conclude that volumes of gas delivered in interstate commerce pursuant to the provisions of section 2.56a shall not also serve to discharge refund obligations or trigger contingent escalations.

The Producers request several clarifications as to the treatment of refund credits and contingent escalations taken prior to the issuance of Opinion No. 699 where the rate is subsequently increased pursuant to that opinion and the effect of filing the waiver after September 21, 1974. The regulations in section 2.56a(j) [formerly §2.56 (h)(11)] have been modified to reflect as the effective date of the required waiver the date of filing if the filing is made after September 21, 1974. The other clarification, we think, to be implicit in Opinion No. 699, however, we shall make it explicit. The national rate is obtained by waiving future refund credits and contingent escalations and the waiver required under section 2.56a(i) does not affect refund credits or contingent escalation dedications for volumes of gas delivered prior to the time that a rate increase filing and accompanying waiver under section 2.56a(i) becomes effective pursuant to section 2.56a(j).

134. *Nationwide Rulemaking To Establish Just And Reasonable Rates For Natural Gas Produced From Wells Commenced Before January 1, 1973*, 38 Fed. Reg. 14295 (1973), *see* "Notice Issuing Staff Rate Recommendation And Prescribing Procedures," 39 Fed. Reg. 34304 (September 12, 1974).

[3584]

V

PIPELINE PGA FILINGS

United Gas Pipe Line Company (United), Panhandle Eastern Pipe Line Company (Panhandle), and Trunkline Gas Company (Trunkline) urge the Commission to allow pipeline companies having purchase gas adjustment (PGA) clauses to make special filings to recover the increased rates provided by Opinion No. 699.[135] We believe that such relief is provided by the statement of policy relating to PGA filings which permits pipelines to recover the increased costs associated with the national rate through the deferred account part of their purchase gas adjustment clauses.[136]

We have determined that jurisdictional pipelines should be permitted to make a one-time special PGA filing to track the rates prescribed in this opinion. Thus, we shall waive the requirements of section 154.38(d)(4)(ii) to permit the filing of this special PGA increase on or before March 3, 1975, to track all increases in purchase gas costs attributable to the national rate which are in effect pursuant to filings made by natural gas producers under section 2.56a(j) on or before January 31, 1975. No other increases in purchase gas cost shall be included in such filing. If a pipeline does not make this special PGA filing on or before March 3, 1975, such pipeline will be permitted to track the rates prescribed in this opinion solely through its regular semiannual PGA filings made after March 3, 1975.

135. *See United Gas Pipe Line Company*, 48 F.P.C. 413, 414 (1972).

136. ____F.P.C.____ (November 1974).

[3585]

VI

RATES FOR THE APPALACHIAN-ILLINOIS BASIN AREA

Many parties[137] to this proceeding take issue with our application of the national rate to the Appalachian-Illinois Basin Area. In addition to their comments, several of these parties (IOGA, Ohio Oil and Gas Association, and the Columbia companies) submitted studies for the Appalachian area which show that costs are allegedly in the range of 65 to 78 cents per Mcf for that area.

We are not unmindful of the unique nature of the Appalachian area; however, we are of the opinion that a separate rate, whether as a guideline, interim, or permanent rate, for this area should not be promulgated in this proceeding. There is now pending a proceeding upon a petition for special relief from the national rate for producers in the Appalachian area.[138] This proceeding will develop additional information which may be useful in determining whether separate rates should be established for the Appalachian area in the future and the potential level of those separate rates. In order that natural gas producers in this area not be deprived of the flexibility and expeditious nature of the Commission's rulemaking procedures to

137. Independent Oil and Gas Association of West Virginia (IOGA), Ohio Oil and Gas Association, Columbia Gas System Companies, Equitable Gas Company, Public Service Commission of the State of New York, Oil and Gas Conservation Commission of the State of West Virginia, Kentucky Oil and Gas Association, and Consolidated Natural Gas Company.

138. *Independent Oil And Gas Association Of West Virginia*, Docket No. RI75-21.

[3586]

establish natural gas producer rates, we shall provide that the record in Docket No. RI75-21 will be incorporated into the record of the proceeding in Docket No. RM75-14 which will establish rates for the 1975-76 biennium.[139]

The requests for modification of the national rate regulations promulgated by Opinion No. 699 to establish a separate rate for the Appalachian-Illinois Basin Area are hereby denied.

VII

ROCKY MOUNTAIN RATES AND EL PASO NATURAL GAS COMPANY

The Producers allege that we failed to implement our rate orders for the Rocky Mountain Area[140] and that corrective action should be taken by prescribing the rate finally determined in this proceeding as the just and

[3587]

reasonable rate for sales made under Order No. 435. We agree that corrective action should be taken but we do not agree with the extent of the remedy suggested by the Producers and El Paso.

Because Order No. 435 and Opinion No. 658 have resulted in a rather complex rate structure for the Rocky Mountain Area, a brief review of that rate structure is

139. See 18 C.F.R. §2.56a(m), and n. 99, *supra*.

140. *Initial Rates For Future Sales Of Natural Gas For All Areas*, Docket Nos. R-389, R-389-A, Order No. 435, 46 F.P.C. 68 (1971), *affirmed sub nom. American Public Gas Association, et al. v. FPC*, 498 F.2d (D.C. Cir., May 23, 1974); *Area Rates For The Rocky Mountain Area*, Docket No. R-425, Opinion No. 658, 49 F.P.C. 924 (1973).

[3588]

necessary. Order 435 promulgated initial rates at which permanent certificates would be issued without refund obligation for new sales of natural gas made under contracts dated after June 17, 1970.[141] Opinion No. 658 established the just and reasonable rate for sales made under contracts dated prior to October 1, 1968, from wells commenced prior to January 1, 1973. For new sales of natural gas made from wells commenced on or after January 1, 1973, on acreage dedicated under contacts dated prior to October 1, 1968, and for sales made under contracts dated between October 1, 1968, and June 17, 1970, Opinion No. 658 held that the Order 435 rates would apply to such sales until a final order was issued in this proceeding.[142] Thus, if we were to implement the Rocky Mountain orders as suggested by the Producers certain dedications to the interstate market prior to January 1, 1973 would qualify for the rates established in this proceeding while similar sales made in other areas would not qualify for these rates.

We find that rates for the Rocky Mountain Area for contracts dated on or after October 1, 1968, where the sales do not qualify for the national rate pursuant to section 2.56a(a)(2) [18 C.F.R. §2.56a(a)(2)], shall be 35 cents per Mcf.[143] This rate is based upon our analysis of the

[3588]

cost studies incorporated in Order No. 435[144] and the

141. Order No. 435, 46 F.P.C. 68, 84, 85 (1971).

142. 49 F.P.C. 924 at 927.

143. This rate shall also apply to qualifying sales prior to June 21, 1974.

144. 46 F.P.C. 63 at 84.

[3588]

rates, based upon national data, established in *Permian II*.[145] This rate is exclusive of all production, severance, or similar taxes, State or Federal, and subject to quality adjustments and gathering. All amounts collected in excess of these rates subject to refund shall be refunded to the purchaser for flow through to the ultimate parties who paid excessive rates for such gas.[146]

Table III indicates that the amount of refunds required by the promulgation of a 35 cents per Mcf rate is not significant. There is, of course, a pressing need for additional capital to finance exploration and development activities, but we believe that the public interest requires that just and reasonable rates for past periods be finally rendered for sales made in the Rocky Mountain Area. The rates for future periods for sales made in all areas will be determined in this proceeding, Docket No. R-478, and Docket No. RM75-____.

[3589]

VIII

SMALL PRODUCERS

Several questions regarding the interrelationship of the national rate and just and reasonable rates for small producers including the effective date of the rates promulgated in Opinion No. 699 were raised.

The effective date of the rates promulgated by Opinion No. 699 is June 21, 1974.[147]

145. 50 F.P.C. 390 (1973).

146. Because of our treatment of refund credit and contingent escalation provisions, *supra* at 60-63 we find that such provisions should not be included in the rate structure for the Rocky Mountain Area.

147. *Infra* at 71.

Pending the resolution of the applicable standards upon which the justness and reasonableness of small producer rates will be determined,[148] small producers are entitled to collect the national rate for qualifying sales on and after June 21, 1974, without a refund obligation.

There may be some confusion with respect to the language pertaining to expiring contracts at page 108 of Opinion No. 699. As with expiring contracts entered into by large producers, small producers must execute a renewal contract which qualifies pursuant to section 2.56 (a)(2)(iii) before they are eligible to collect the rate prescribed in section 2.56a(a)(1) for such continued sales.

[3590]

IX

CLARIFICATIONS AND MODIFICATIONS

There are also a number of other matters which should be mentioned. These matters relate to certain technical modifications and amendments to the national rate regulations.

A. *Codification of National Rate Regulations*

Opinion No. 699 provided that the national rate regulations would be codified as subsection (h) of section 2.56 of the Commission's Statements Of General Policy And Interpretations (18 C.F.R. §2.56) entitled "Area Price Levels for Natural Gas Sales by Independent Producers." Upon further consideration of this codification, we believe that the national rate regulations should be codified as a

148. *Small Producer Regulation,* Docket No. R-393, "Notice of Proposed Rulemaking," 39 Fed. Reg. 33241 (September 1974).

separate section of the Statements Of General Policy And Interpretations to avoid confusion with the guideline and initial rate provisions of section 2.56.

Thus, we have deleted section 2.56(h) and codified the amended national rate regulations as section 2.56a. Section 2.56a(o) provides for amendment of all certificates which have been issued pursuant to section 2.56(h) to reflect the change in codification.

B. *Appendix D*

The Producers request that footnote 4 to Appendix D be altered to reflect the language of section 2.56(h)(7) [now section 2.56a(e)]. The second sentence of that footnote reads:

> Note that only natural gas produced in offshore areas actually delivered onshore by producer's facilities qualifies for this adjustment.

[3591]

The sentence should read:

> Note that only natural gas produced in offshore areas which is actually delivered onshore at the sole cost of the producer qualifies for this adjustment.

C. *Effective Date of Opinion No. 699*

Several parties have requested clarification as to the effective date of the rates prescribed in Opinion No. 699. The effective date of the national rate prescribed in section 2.56a (formerly section 2.56(h) is June 21, 1974.

The rate which is prescribed by this opinion is being made effective June 21, 1974, to assure that the national

rate will provide the rate of return determined to be just and reasonable in Opinion No. 699 and this opinion, pursuant to the Commission's authority upon rehearing "to abrogate or modify its order without further hearing."[149] Such an effective date is necessary to assure that those persons selling natural gas in interstate commerce will receive the rates which this Commission has ultimately found to be just and reasonable.

[3592]

D. *Miscellaneous Amendments*

A number of parties presented to the Commission on rehearing requests for clarifications of the promulgated national rate regulations. In many cases these clarifications have been incorporated in the amended national rate regulations without explicit discussion in this opinion. To the extent that the proposed clarifications are reflected in the amended regulations, these requests for modification of Opinion No. 699 and the regulations promulgated thereunder are granted. Those requests which are not reflected in the amended regulations promulgated by this opinion are hereby denied.

[3593]

X

CONCLUSION

By Opinion No. 699 and this opinion, we establish a

149. 52 Stat. 831 (1938), 15 U.S.C. §717r (1970); *see also* 52 Stat. 830 (1938), 15 U.S.C. §717o (1970); *cf. Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (slip opinion at 23-25); *Austral Oil Co. v. FPC*, 428 F.2d 407, 444-445, *on rehearing*, 444 F.2d 125, 126-127 (5th Cir.), *cert. denied sub nom. Municipal Distributors Group v. FPC*, 400 U.S. 950 (1970).

rate design for new gas[150] sold in interstate commerce. Each of the elements of the rate structure is interdependent upon all of the other elements and stands not by itself but as part of the whole. In summary, the total rate design herein found to be just and reasonable consists of the following integral elements:

1. A base rate of 50.0 cents per Mcf (with annual escalations of 1.0 cents per Mcf) subject to Btu adjustment plus reimbursement for production, severance, or similar taxes, and gathering allowances (including the onshore delivery of offshore gas at the cost of the producer) for qualifying sales;
2. Allowance of the national rate for sales formerly made pursuant to contracts which have expired by their own terms where a qualifying renewal contract is submitted to the Commission for certification;
3. A biennial review to prescribe prospective just and reasonable rates for those sales which qualify for the national rate; and
4. Provisions for special relief from the national rate.

We have "adopted a total rate structure to motivate private producers to fully develop [the nation's natural

[3594]

gas] resources"[151] while assuring the consumer an adequate supply of gas at a reasonable rate. This "total rate

150. New gas is that gas which qualifies under one or more of the provisions of section 2.56a(a)(2).

151. *Placid Oil Co. v. FPC*, 483 F.2d 880, 891 (1973), *affirmed sub nom. Mobil Oil Corp. v. FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974) (see slip opinion at 43).

structure" as promulgated in Opinion No. 699 and supplemented and modified by this opinion represents a solution "capable of equitably reconciling the diverse and conflicting interests"[152] which are presented on the record of this proceeding. It is true that certain portions of this rate structure favors some producers or some consumers more than other members of those classes of persons. There is always "some discrimination aris[ing] from the mere fact of [national], rather than individual producer, regulation,"[153] but such discrimination is permissible if the overall balance of the order is not unjust and unreasonable. We are of the opinion that the "overall balance" of the rate structure established herein is just and reasonable.

[3595]

The Commission, acting pursuant to the provisions of the Natural Gas Act, as amended, particularly Sections 4, 5, 7, 8, 14, 15, and 16 thereof (52 Stat. 822 823, 824, 825, 828, 829, 830 (1938); 56 Stat. 83, 84 (1942); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. §§717c, 717d, 717f, 717g, 717m, 717n, 717o (1970)0, *orders:*

(A) The Statements of General Policy and Interpretations of The Commission, Part 2 of Subchapter A of Chapter I of Title 18 of the Code of Federal Regulations, are hereby amended by deleting Section 2.56(h) adding a new Section 2.56a as follows:

2.56a National Rate For Sales Of Natural Gas From Wells Commenced On Or After January 1,

152. *Mobil Oil Corp. v. FPC,* 42 U.S.L.W. 4842 (slip opinion at 43) *citing Permian Basin Area Rate Cases,* 390 U.S. 747, 767 (1968).

153. *Mobil Oil Corp. v. FPC,* slip opinion at 37.

1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973

(a) *Base National Rate*

(1) Notwithstanding any other provisions of the General Rules of the Federal Power Commission, or the Regulations Under the Natural Gas Act, sales of natural gas which qualify under the provisions of one or more of the classifications set forth in paragraph (2) may be made in interstate commerce at a rate not to exceed 50.0 cents per Mcf (at 14.73 psia), exclusive of all State or Federal production, severance or similar taxes, and subject to the adjustments provided in this Section 2.56a.

(2) Sales of natural gas in interstate commerce for resale may be made at the rate prescribed in paragraph (1) of this subsection provided the provisions of one or more of the following classifications apply to such sales:

[3596]

(i) The sale is made from a well or wells commenced on or after January 1, 1973;

(ii) Sales made pursuant to contracts for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1973, except pursuant to the provisions of 18 C.F.R. §§ 2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission

Order No. 491, *et al.*), or 18 C.F.R. § 2.75(n), where such sales are initiated on or after January 1, 1973, provided that no certificate for the subject sale has been issued under the optional procedure (18 C.F.R. § 2.75);

(iii) Sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

[3597]

(3) The price prescribed by this Subsection (a) may be increased by an amount not to exceed 1.0 cents per Mcf per annum commencing on January 1, 1975, and the first day of every year thereafter for the term of the contract dedicating the subject gas for sale in interstate commerce pursuant to the terms of the sales contract until such time as the price prescribed in paragraph (1) of this subsection (a) shall be redetermined according to the provisions of Subsection (n) of this section 2.56a.

(b) *Tax Adjustments*

The applicable rate prescribed in subsection (a)

shall be adjusted upward for all State or Federal production, severance, or similar taxes, effective the date deliveries are commenced, and shall be adjusted upward by 100 percent of any increase in such taxes subsequent to the date deliveries were commenced, and shall be adjusted downward by 100 percent of any decrease in such taxes subsequent to the date deliveries were commenced.

(c) *Quality Adjustments*

For natural gas sold in interstate commerce for resale subject to the rate prescribed in subsection (a) of this section, quality standards and the resulting adjustments to the base national rate shall be made as follows:

[3598]

(1) *Btu Adjustment*

For natural gas containing more than 1,000 Btu's per cubic foot, at 60°F. and 14.73 psia, upward adjustments shall be made on a proportional basis from a base of 1,000 Btu's per cubic foot; and for natural gas containing less than 1,000 Btu's per cubic foot, at 60° F. and 14.73 psia, downward adjustments shall be made on a proportional basis from a least of 1,000 Btu's per cubic foot.

This adjustment shall be made after the rate prescribed in subsection (a)(1) is adjusted for taxes pursuant to subsection (b).

The Btu content of the natural gas used in computing this rate adjustment shall be the

number of British thermal units (Btu) produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1.0 cubic feet at a temperature of 60°F. saturated with water vapor and under a pressure equivalent to that of 30.00 inches of mercury at 32°F. and under standard gravitational force (980.665 centimeters per second squared) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air and when the water formed by combustion is condensed to the liquid state.

(2) *Other quality Adjustments*

All quality standards and the resulting adjustments to the rate prescribed in subsection (a)(1) shall be made in accordance with the provisions of the particular gas sales contract except that all Btu adjustments shall be governed by paragraph (1) of this subsection.

[3599]

(d) *Gathering Allowances*

The base national rate prescribed in subsection (a) of this section, as adjusted for Btu content and applicable taxes, shall be adjusted for gathering activities as follows:

(1) *Appalachian-Illinois Basin Areas*

The gathering allowance shall be 1.0 cents per Mcf for all sales of natural gas made from wells located in the Appalachian-Illinois Basin Areas.

(2) *Hugoton-Anadarko Area*

The gathering allowance shall be the amounts prescribed below where delivery of the gas is made after substantial off-lease gathering by the producer, whether at a plant tailgate or at a central point in the field.

(A) For gas produced in the Panhandle and Hugoton Fields, the allowance shall be 2.5 cents per Mcf.

(B) For gas produced from fields or reservoirs other than the Panhandle or Hugoton Fields (the "Other Fields"), the allowance shall be 1.0 cents per Mcf.

(3) *Other Southwest Area*

The gathering allowance shall be the amounts prescribed below where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

[3600]

(A) For gas produced in the Other Oklahoma Area, Texas Railroad District No. 9, and Northern Arkansas, the allowance shall be 1.5 cents per Mcf.

(B) For gas produced in Texas Railroad District Nos. 5 and 6, Northern Louisiana, and Southern Arkansas, the allowance shall be 1.0 cents per Mcf.

(C) For gas produced in Mississippi and Alabama, the allowance shall be 1.25 cents per Mcf.

(4) *Permian Basin Area*

For gas produced in the Permian Basin Area, the applicable gathering allowance shall be 1.5 cents per Mcf where delivery is made after substantial off-lease gathering by the producer, whether at a plant tailgate or a central point in the field.

(5) *Rocky Mountain Area*

For gas produced in the Rocky Mountain Area, the applicable gathering allowance shall be 1.0 cents per Mcf where delivery is made to the buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

(6) *Southern Louisiana Area*

For gas produced in the Southern Louisiana Area, the applicable gathering allowance shall be 0.5 cents per Mcf where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

[3601]

(7) *Texas Gulf Coast Area*

For gas produced in the Texas Gulf Coast Area, the applicable gathering allowance shall

be 0.4 cents per Mcf where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(e) *Delivery of Offshore Gas By the Producer to an Onshore Area*

If natural gas produced offshore is delivered onshore, at the sole cost of producer, the uniform national rate shall be adjusted upward 1.0 cent per Mcf for such offshore gas.

(f) *Adjusted National Rate*

The uniform national rate prescribed in subsection (a), as adjusted pursuant to subsections (b), (c), (d), and (e), is the adjusted national rate, and such rate is applicable only to those jurisdictional sales described in subsection (a) (2) made within the United States including the adjacent offshore Federal domain but excluding Alaska and Hawaii. No seller may demand or recieve any rate or charge in excess of the rate prescribed by subsection (a), except for such adjustments described in subsections (b), (c), (d), and (e) of this section as may be applicable to the particular sale, unless the Commission after giving proper notice

[3602]

and providing an opportunity for the submission of comments shall modify the rate set forth in subsection (a) or grant a petition for

special relief pursuant to subsection (g) of this section.

(g) *Special Relief*

Prior to the establishment of rates for the 1975-76 biennium pursuant to subsection (n), any seller seeking to charge a rate in excess of the adjusted national rate described in subsection (f) of this section or requesting a change in either the base national rate prescribed in subsection (a)(1) or the adjusted national rate described in subsection (f) must file a petition seeking special relief for waiver or amendment of said subsections pursuant to Section 1.7(b) of the Commission's Rules of Practice and Procedure (18 C.F.R. §1.7(b) fully justifying the relief sought in light of this order. Such seller may not file for any rate increase which results in a rate in excess of the adjusted national rate described in subsection (f) unless and until the Commission grants such petition for special relief.

(1) *Federal Income Taxes*

For those cases where a producer seeks special relief on the grounds that a Federal income tax liability has been incurred with respect to the producer's total jurisdictional natural gas operations, the producer shall submit certified copies of the appropriate Federal income

[3603]

tax returns and supporting schedules required by Treas. Regs. §§1.611-3(g), 1.613-6 (26

C.F.R. §§1.611-2(g), 1.613-6) as part of the petition for special relief.

(2) ***Drilling Depths Greater Than 15,000 Feet and Water Depths Greater Than 250 Feet***

For sales of natural gas made from wells with a total depth greater than 15,000 feet (8,000 feet in the Appalachian and Illinois Basin Areas) and/or located in water depths greater than 250 feet, the seller may petition the Commission for relief from the rate established in subsection (a)(1) and such relief may be granted by the Commission upon a showing that total cost of producing such gas is in excess of the rate established in this decision.

(h) *Modification of Area Rate Regulations*

To the extent that the Commission's Regulations Under the Natural Gas Act establishing area rates and conditions for sale of natural gas from the Southern Louisiana Area (18 C.F.R. §154.105), Hugoton-Anadarko Area (18 C.F.R. §154.106), Appalachian Basin Area (18 C.F.R. §154.107), Illinois Basin Area (18 C.F.R. §154.109), Other Southwest Area (18 C.F.R. §154.109a), or Rocky Mountain Area (18 C.F.R. §§2.56(a), 154.109(b)), and the Permian Basin Area are inconsistent with the provisions set

[3604]

forth above the same are hereby modified to re-

flect the provisions set forth above. The provisions of the rate structures for these are modified only with respect to those sales which are certificated pursuant to the provisions of this section and in all other respects remain in full force and effect. Provisions pertaining to refund credits and contingent escalations are contained in subsection (i).

(i) *Waiver of Refund Credits and Contingent Escalations.*

Any natural gas certificated under the provisions of this section which a natural gas producer elects to have credited against his existing refund obligations in the Southern Louisiana, Texas Gulf Coast, Other Southwest Area, or the Permian Basin, or applied to the triggering volumes for the contingent escalations for those areas shall be priced at the rate prescribed in the applicable area rate opinion and not at the uniform national rate prescribed in this opinion. For purposes of this section, the applicable area rate opinions and Commission regulations are

(a) *Area Rate Proceeding (Texas Gulf Coast Area), et al.,* Opinion No. 595, 45 F.P.C. 675 (1971); 18 C.F.R. §154. 109.

(b) *Area Rate Proceeding (Southern Louisiana Area), et al.,* Opinion No. 598, 46 F.P.C. 86 (1971); 18 C.F.R. §154. 195.

[3605]

(c) *Area Rate Proceeding (Other Southwest Area), et al.,* Opinion No. 607-A, 47 F.P.C. 99 (1972); 18 C.F.R. §154. 109a.

(d) *Area Rate Proceeding (Permian Basin Area II),* Docket No. AR70-1 (Phase I), Opinion No. 662, 50 F.P.C. 390 (1973).

With respect to gas of a class described in subsection (a)(2) which is currently being sold in interstate commerce in discharge of a refund obligation or was dedicated to interstate commerce in partial satisfaction of the triggering volumes for the contingent escalations in the described areas, such gas may be sold at the rate prescribed in subsection (a) only if the seller files a written waiver of the right with respect to such gas to discharge such refund obligations or to trigger the contingent escalations concurrently with the contractually autorized rate increase filing. The seller shall further state the date on which the subject wells were commenced, the present provisions under which the gas is being sold in interstate commerce, the dollar amount of existing refund obligations previously discharged by the sale of such gas, and the volumes (at 14.73 psia) applied to trigger the contingent escalations.

(j) *Effective Date of Rate Filings and Waivers of Refund Credits or Contingent Escalations*

Any contractually authorized increased rate

filing and/or written waiver of refund credits or contingent escalations made pursuant to

[3606]

the provisions of this order shall be effective as of June 21, 1974, if the filing is made on or before January 31, 1975, and as of the date of filing if the filing is made subsequent thereto. Such filings may include the 1.0 cents per Mcf annual escalation to be effective January 1, 1975.

(k) *Newly Discovered Reservoirs On Previously Committed Acreage*

(1) In all areas, the rate for natural gas produced from a reservoir discovered on or after January 1, 1973, which is located upon acreage previously dedicated to interstate commerce under a contract dated prior to January 1, 1973, shall be determined by the date of discovery of such reservoir, in lieu of the contract date. (2) Where a producer is entitled to an increase in the price of its gas based on the date of discovery of the reservoir from which gas-well gas sales (or residue gas derived therefrom) are being made, it may file a proposed price increase pursuant to section 4 of the Natural Gas Act, indicating to what gas the higher price will be applicable. With each filing the producer will include (i) copies of all documents filed with or issued by local or State regulatory agencies relating to the discovery of the reservoir from which the gas is produced, and (ii)

a statement by the buyer of the gas that the gas qualifies

[3607]

for the price sought, or why the buyer believes it does not. The producer shall also furnish any additional material in its possession or available to it which the Commission may request in writing. Documents or other data previously filed with this Commission, whether by the producer or another, may be incorporated by reference in any filing hereunder. Similar information shall be filed in any pending section 4 proceeding to which it is relevant. The Commission will follow the determination made by the appropriate State agency in determining the date of discovery of a reservoir. In the event the State agency changes its classification of a reservoir, the Commission shall follow such change as of the date of the new classification.

Whenever the reclassification of a reservoir affects the applicable ceiling rate the producer and the buyer shall notify the Commission.

(l) *Pipeline Production*

Natural gas production from leases owned by a pipeline or a pipeline affiliate may be priced at the rate prescribed in subsection (a) pursuant to the provisions of Section 2.66(c) of this part (18 C.F.R. §2.66(c)).

[3608]

(m) *Termination of Rate Ceiling*

The rate prescribed in subsection (a)(1) shall

remain in effect until such time as rates are established pursuant to subsection (n).

(n) *Review of National Rate Ceiling*

Prior to January 1, 1975, the Commission shall initiate such proceedings as shall be necessary to establish a just and reasonable rate to be effective from the date of establishment of rates by order of the Commission through December 31, 1976, for the sales described in subsection (a)(2) and for all wells commenced on or after January 1, 1975, and prior to January 1, 1977, all new dedications of natural gas to interstate commerce for the period January 1, 1975, through December 31, 1976, and all renewal contracts taking effect for the period January 1, 1975, through December 31, 1976.

(o) *Revision of Section* 2.56(h) (18 C.F.R. §2.56(h)

By Opinion No. 699, the Commission promulgated a national rate structure as subsection (h) of Section 2.56 of its General

[3609]

Policy Statements and Interpretations (18 C.F.R. §2.56(h)). By this Opinion No. 699-E, said section 2.56(h) is revised and designated as Section 2.56a (18 C.F.R. §2.56a). All certificates which may have been issued prior to this date pursuant to Section 2.56(h) are hereby amended to reflect the change in codification of the national rate structure.

(p) *Effective Date*

The effective date of this section 2.56a is June 21, 1974.

(B) Section 2.56(f) of the Commission's General Policy Statements and Interpretations, Part 2 of Subchapter A of Chapter I, Title 18, Code of Federal Regulations, is amended by adding a new paragraph (3):

(3) *Reservoirs Discovered or Dedicated to Interstate Commerce On or After January 1, 1973.* The rate for new reservoirs discovered or dedicated to interstate commerce on or after January 1, 1973, shall be determined by Section 2.56a(a) if the proposed sale comes within one of the classes enumerated in Section 2.56a(a)(1)

(C) Section 2.66 of the Commission's General Policy Statements and Interpretations, Part 2 of Subchapter A of Chapter I, Title 18 of the Code of Federal Regulations, is amended by adding a new subsection (c) as follows:

[3610]

(c) *National Rate for Pipeline or Pipeline Affiliate Production*

Notwithstanding any other provision of this section 2.66, natural gas production from any lease owned by a pipeline company or a pipeline affiliate, regardless of the date of acquisition of the lease, shall be priced for ratemaking purposes at the rate prescribed in section 2.56a(a)(1) of this part if such production qualifies under the provisions of one or more of the enumerated classes of sales set forth in section 2.56a(a)(2) of this part. The provisions of Section 2.56(f) (18 C.F.R. §2.56(f)) shall apply to natural gas production which qualifies for the national rate treatment pursuant to this subsection (c).

(D) Notwithstanding the provisions of section 154.38 (d)(4)(iv) of the Regulations Under the Natural Gas Act (18 C.F.R. §154.38(d)(4)(iv)), any jurisdictional pipeline company having a purchase gas adjustment clause in effect on June 21, 1974, and thereafter, pursuant to section 154.38(d)(4), may file on or before March 3, 1975, a special rate increase to track the rates prescribed in section 2.56a (18 C.F.R. §2.56(a)) effective as of the date of the filing, provided such rates are in effect pursuant to filings made by natural gas producers pursuant to section 2.56a(j) on or before January 31, 1975.

(E) Section 154.109b of the Commission's Regulations Under the Natural Gas Act, Part 154 of Subchapter E of Chapter I, Title 18, Code of Federal Regulations, is hereby amended by adding a new subsection (d):

[3611]

(d) No rate or charge, made, demanded, or received under a rate schedule filed pursuant to this part for gas produced in the Rocky Moutain Area shall exceed 35.0 cents per Mcf measured at 14.73 psia and 60°F, subject to adjustment upward and downward Btu adjustment on a proportional basis from a base Btu content of 1,000 Btu's per cubic foot measured on a saturated basis, and exclusive of all State or Federal production, severance, or similar taxes, and sold under contracts dated on or after October 1, 1968, for wells commenced prior to January 1, 1973. This rate shall also be subject to a gathering allowance not to exceed 1.0 cents per Mcf where delivery is made to the

buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

By the Commission. Commissioner Brooke, concurring, filed a separate statement appended hereto.

(SEAL)

Commissioner Springer, concurring in part and dissenting in part, filed a separate statement appended hereto.

Commissioner Smith, concurring in part and dissenting in part, filed a separate statement appended hereto.

Commissioner Moody, dissenting, filed a separate statement appended hereto.

Mary B. Kidd,
Acting Secretary.

TABLE I

Non-Associated Gas Reserve Additions For the United States */
MMCF at 14.73 psia
(Excludes Alaskan Data)

Year	Revisions (a)	Extensions (b)	New Field (c)	New Reservoir (d)	Total 1/ (e)	Total Excluding Revisions (f)
1966	3,056,812	7,490,746	2,813,222	2,775,360	16,135,140	13,079,328
1967	3,712,892	8,625,273	2,819,635	2,126,298	17,284,098	13,571,206
1968	4,036,210	5,864,521	1,206,628	1,227,600	12,334,959	8,298,749
1969	(1,440,196)	4,788,627	1,653,266	1,863,021	6,874,718	8,314,914
1970	(290,034)	4,886,132	1,556,494	3,198,724	9,351,316	9,641,350
1971	(1,471,410)	5,625,841	1,176,939	3,234,033	8,565,403	10,036,813
1972	(1,911,097)	5,449,052	1,264,756	2,794,559	7,597,270	9,508,367
1973	(5,347,021)	5,305,857	1,968,520	1,789,574	3,734,930	9,063,951

1/ These totals equal the summation of Columns (a) through (d). The parentheses () in Column (a) denote negative amounts.

*/ Reserves Of Crude Oil, Natural Gas Liquids, And Natural Gas In The United States And Canada And United States Productive Capacity As Of December 31, 1973, Volume 28, Published Jointly by the American Gas Association, American Petroleum Institute, and the Canadian Petroleum Institute (June 1974).

TABLE II

REVISIONS TO NON-ASSOCIATED NATURAL GAS RESERVES

(Total United States excluding Alaska)

(Billions of Cubic Feet (Bcf) at 14.73 psia, 60^{o} F.)

	1966	1967	1968	1969	1970	1971	1972	1973
Positive Revisions	4323	5713	6234	1368	2208	2000	1426	1422
Negative Revisions	(1267)	(2001)	(2200)	(2812)	(2500)	(3471)	(3337)	(6763)
Net	3056	3712	4034	1444	(292)	(1471)	(1911)	(5341)

( ) Indicates negative volumes

Source: Comments Of United Distribution Companies In Response To Notice Issued March 21, 1974, Separate Appendix Prepared By William J. Ogden, Table 6 (May 7, 1974).

TABLE III

Rocky Mountain Area
Rates Subject to Refund Where Base
Rate is in Excess of 30¢ per Mcf

Producer - P/L	Docket No.	Base Rate	R/S No.	Supp. No.	Estimated Annual Amount Suspended $	Estimated Annual Volume (a)	Date Rate ESR	Portion of Rate in Excess of 30¢ (b)	Portion of Rate in Excess of 35¢ (c)	Portion of Rate in Excess of 42¢ (d)	Monthly Revenue From Portion of Rate in Excess of 30¢ (e)	Monthly Revenue From Portion of Rate in Excess of 35¢ (f)	Monthly Revenue From Portion of Rate in Excess of 42¢ (g)
Montana-Wyoming													
High Crest Northern	RI74-79	40.0¢	1	4	1,879,819	9,125,000	5/9/74	10.0	5.0	-	76,042	38,021	-
High Crest Northern	RI74-174	40.0¢	2	4	208,310	1,080,000	8/22/74	10.0	5.0	-	9,000	4,500	-
Amoco Col. Interstate	RI74-66	41.02¢	582	3	12,748	700,000	4/23/74	11.02	6.02	1.02	6,428	3,512	595
Champlin Mountain Fuel	RI74-233	40.0¢	125	2	112,380	600,000	10/19/74	10.0	5.0	-	-	-	-
Belco Mountain Fuel	RI73-196	32.0¢	7	12	320	100,000	4/23/74	2.0	-	-	167	-	-
Belco Mountain Fuel	RI74-190	33.0¢	7	11	8,112	600,000	8/31/74	3.0	-	-	1,500	-	-
San Juan													
Aztec El Paso	RI74-144	52.16¢	35	11	41,371	120,791	7/2/74	22.16	17.16	10.16	2,231	1,727	1,023
Aztec El Paso	RI74-144	52.16¢	29	10	52,943	158,095	7/2/74	22.16	17.16	10.16	2,920	2,261	1,339
Aztec El Paso	RI74-144	52.16¢	28	8	16,502	48,182	7/2/74	22.16	17.16	10.16	890	689	408
Aztec El Paso	RI74-144	52.16¢	12	13	707	2,065	7/2/74	22.16	17.16	10.16	38	30	18
Aztec El Paso	RI74-144	52.16¢	5	8	15,225	44,450	7/2/74	22.16	17.16	10.16	821	636	376
Aztec El Paso	RI74-144	52.16¢	4	39	158,485	462,733	7/2/74	22.16	17.16	10.16	8,545	6,617	3,918
Aztec El Paso	RI74-144	52.16¢	3	31	547,271	1,597,870	7/2/74	22.16	17.16	10.16	29,507	22,850	13,529
Amerada Hess El Paso	RI75-31	52.16¢	25	8	415,097	1,248,788	2/12/75	22.16	17.16	10.16	-	-	-
Amerada Hess El Paso	RI75-31	52.16¢	49	13	392,321	1,390,717	2/12/75	22.16	17.16	10.16	-	-	-
Amerada Hess El Paso	RI75-31	52.16¢	50	18	55,001	169,027	2/12/75	22.16	17.16	10.16	-	-	-
										Totals	$138,089	$80,843	$21,206

[3615]

OPINION NO. 699-H

Just And Reasonable National Rates For Sales of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973	)	Docket No. R-389-B

(December 4, 1974)

BROOKE, Commissioner, *concurring:*

I concur in the instant order on rehearing of Opinion No. 699, not that I am convinced of its adequacy to maximize the search for new interstate gas supplies but because it does represent a departure from the hitherto sancrosanct Permian costing methodology and movement toward a more realistic economic method for determining the most effective level of producer rates.

Commissioner Moody's dissent details and develops at some length many of the inadequacies and infirmities of the modified national rate order herein adopted, and I am in strong agreement with his analysis and conclusions. However, I am compelled to concur in the order, despite these serious misgivings, because the public interest demands its issuance without further delay, for two major reasons: (1) the producing and pipeline industries and the ultimate consumers are entitled to this early answer to the rate and other important issues, and (2) it is urgent to clear Opinion No. 699-H so we may proceed immediately with the 1975-76 biennium rate review.

Although substantial legal precedents permit considerable latitude in prescribing a just and reasonable national rate, the Commission has chosen to nibble at, rather than take the big bite of the apple that I feel could be legally justified and sustainable on the present record.

Adjusting the Permian model by utilizing discounted cash flow (DCF)to assure a constant 15 per cent return on all invested funds over the life of the investment and trending successful and dry hole costs is a substantial improvement in rate-making methodology. While completely agreeing with this modification, it can only be viewed as a beginning step

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toward more responsive and viable procedures attuned to the desperate need to expand the nation's supplies of *new* natural gas reserves.

The total modified rate for 1973-4 prescribed herein—a base rate of 50 cents plus adjustments—is a much improved incentive, but I regard it as woefully inadequate to enable the interstate pipelines to compete with any degree of effectiveness for new on-shore supplies. Again, the modified 50-cent base rate is entirely cost-based and omits inclusion or consideration of reasonable non-cost add-ons the courts have held to be lawfully permissible where justified. More weight should have been attached to these non-cost factors.

If E&D were directed solely to develop new supplies for the interstate market, the national rate derived herein undoubtedly would be most attractive to potential investors. The precise relationship of price and supply is impossible to define, but it is noteworthy that higher rates,

both intrastate and interstate, have been accompanied by a significant increase in drilling activity the past two years, most of it on-shore. This points up the simple economic fact that high intrastate prices are an effective damper on producer enthusiasm to develop on-shore reserves for the interstate market. I am confident nevertheless that the improved incentives will yield some benefits to the interstate consumer; that rate incentives plus improved cash flow on contract renewals will tend to accelerate off-shore federal domain, and that new entrants may now find gas E&D worth the gamble.

The ultimate effectiveness of the new rate can only be demonstrated through time and experience. It undoubtedly will be more helpful than old rate levels, but it falls short of providing the incentive required to maximize development of the nation's natural gas resource base at this critical juncture of our American livelihood. Curtailments of pipeline supplies are deepening. The producibility from old established reservoirs is dwindling, and living from these inventories will be more difficult and more costly each year. Experts may disagree on the extent of the nation's natural gas potential, but there is universal agreement that the vast bulk of future supplies is in deep on-shore and off-shore horizons below 15,000 feet, in deep water off-shore, in deep tight-bearing formations, in marginal areas previously unattractive

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economically, and in Alaska—all representing the probability of substantial investment.

Converting the natural gas potential from these sources into deliverable supplies will require an enormous invest-

ment of capital, which will not be committed in the absence of incentives which render the expectation of adequate return with greater certainty than the anticipation of loss. Unless a sharp reversal of domestic natural gas supply trends occurs within the next couple of years, the national goal of self-sufficiency will be delayed; curtailments and allocations will impose severe hardships on industry, and, probably, on human needs customers; dependency on foreign suppliers will mount, and prices will increase. The ultimate loser, or course, will be the consumer—the person whom the Natural Gas Act was devised to protect.

/s/ ALBERT B. BROOKE, JR.
Albert B. Brooke, Jr.
Commisisoner

[3618]

Just And Reasonable National Rates For	)	
Sales of Natural Gas From Wells	)	
Commenced On Or After January 1,	)	Docket No.
1973, And New Dedications Of	)	R-389-B
Natural Gas To Interstate Commerce	)	
On Or After January 1, 1973	)	

(December 4, 1974)

SPRINGER, Commisisoner, *Concurring in Part and Dissenting in Part:*

A HISTORY OF AREA AND NATIONAL RATES 1968-JUNE 1974

In determining the legality of the rule establishing a national rate perhaps a short history is in order.

In 1960, the Federal Power Commission decided to establish area rates rather than regulating on an individual company basis.

The first area rate decision was issued in 1965 and was affirmed in 1968 by the U. S. Supreme Court in the Permian Basin area rate case (390 U.S. 747). In that decision the Commission determined the rates for refulated companies on the basis of the recovery of all of their reasonable expenses, including a fair return on their investment in used and useful properties. In all succeeding area rate cases this method was used in determining the rates including a fair return.

In reaching our decision on June 21, 1974, in Opinion 699 as to a national rate, we followed this method which has been approved by the Court's innumerable times. We

computed our nationwide rates on the basis that a fair return on the investment producers had made for the benefit of consumers was 15%.

It cannot be emphasized too strongly that since this Commission first initiated under R-389-B a proposed rule-making to determine rates on a nationwide basis, it has consistently applied the methodology approved in its previous area rate cases in reaching a nationwide rate.

On June 21, in this proceeding the Commission issued Opinion 699 wherein we determined that a nationwide price of 42¢ plus one cent annual escalation was the proper price for all gas sold on or after January 1, 1973, from wells or

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contracts after that date. In determining that 42¢ was the proper rate, we were presented with cost evidence by our staff and others indicating that the range of cost using our approved methodology was between 38 and 42 cents and thus we granted a rate at the high end of that range. We adopted the high range in order to assure the producers that they would have every incentive to find and sell additional gas in the interstate market.

The methodology used in the overall determination of a nationwide rate in 699 on June 21, 1974, is a method which has been specifically approved by the courts in the Permian Basin case (supra) and the South Louisiana case (Placid Oil Co. v. FPC, 483 F.2d 880, 5 Cir. 1973).

THE NEW METHODOLOGY

As modified by this proposed opinion, we are increasing that rate which was already at the high end of the range

by nearly 20%; i.e., from 42¢ to 50¢. This is being accomplished in two ways: First, the majority has decided that a completely new method for determining the proper rate of return to be applied, and secondly, they have added to this a form of trending based on speculation as to the future.

Opinion 699, issued on June 21, was adopted after the Commission had received comments from all interested parties as to the proposed rates and given them full and careful consideration. Numerous applications for rehearing were filed both for and against the rate. We granted rehearing for further consideration and on August 22 and 23, 1974, we heard oral arguments from all of the parties requesting rehearing.

After receiving court approval in those cases of the methodology for calculating producer rates, and after working long and hard to apply this methodology to determining a nationwide rate, we suddenly see in the last few weeks a change by the majority to a new methodology.

THE NEW METHODOLOGY AND THE PRODUCER REQUESTS

What is the effect of the new methodolgy? Perhaps a little history of producer requests are in order.

[3620]

In the South Louisiana settlement approved by the Commission on July 16, 1971, the producers assured us that a 26¢ rate would bring forth all the gas needed in the years to come. That was barely 39 months ago. Now the majority is ready to find that either the producers didn't know what they were talking about, or the Commission should never have listened to them. By the proposed

opinion, the majority is increasing the rate by almost 100% from 26¢ to 51¢ Mcf, as of this date.

RATE OF RETURN

I have no objection to examining new methods of regulation when the time is ripe, but to do so at the end of an already decided case strikes me as unusual. More importantly to strike out on a new method of determining rates with as little consideration as seems to be given in this case is something unacceptable to me. The majority starts off with the assumption that their 15% return on investment is a fixed number which cannot be changed when you switch your methodology. They take the 15% allowed on the total rate base and translate it into a discounted cash flow on all producer costs without examining the effect on the traditional methodology of doing this. Let us understand this in the most simple terms. Computed roughly, by switching the methodology, the majority is now saying that producers are entitled to a 23% return on their productive investment.

The majority does not discuss why they need 23%. Neither do they discuss how this compares with the return received by other industries on productive investment, and basically do nothing but grant the substantial increase without an analytical examination of its need or effect.

I cannot but presume that all companies regulated by this Commission-producer, pipeline, and power-will now be entitled to argue that the latest return the majority determined to be reasonable should be translated by the DCF method to a return, in effect, several percentage points higher, since no adjustment is made to the basic starting point for the use of the DCF method.

Under the DCF approach, the rate of return is the discount rate which equates a projected future flow of income to the present market price of equity. I am not prepared to make a sophisticated analysis of this concept

for the gas producer industry, but neither am I ready to adopt the numbers used by the majority without more analysis than they have given them. What they have done is take the figures from Opinion 699, adopted June 21, 1974, and translate them into a DCF method with little or no analysis at all.

ATTRACTING GAS TO THE INTERSTATE MARKET

Without commenting on the use of questionable trending in addition to the DCF method as a means of raising nationwide rates from 42 to 50 cents, I feel that several other points should be noted. First, a use of annual escalations in these rates means that even when we issued Opinion 699, we were talking about 43 cents, and by January 1, 1975, will be talking about 44 cents.

The majority seems to feel that this is a price which will not elicit a supply of gas. However, I note that in the last month at least 16 producers who had contracts at rates well in excess of 43¢ set by Opinion 699, have agreed to accept certificates at that rate. I cannot believe that they would accept this rate if they felt they were not going to earn a fair return at that figure.

Secondly, as noted above, it was only three years ago that producers told us 26¢ would elicit the supply of gas we needed. While I realize costs have increased, it must be remembered that costs of domestic production have

only increased so much and it is only this additional cost we should be trying to allow. I cannot believe that in three years inflation has raised costs 100 percent, nor that in agreeing to a 26¢ price, the producers were not aware at that time that some inflation was bound to occur.

LIMITED TERM EMERGENCY CERTIFICATES

One other aspect of this proceeding in Docket No. R-389-B on which I feel compelled to comment, is our order of September 9, 1974, reinstating, *inter alia,* limited term certificates. I agreed to that order, but in reviewing it, I note that we completely failed to define what we meant by the word *LIMITED.* As written it would appear that Opinion 699-B would allow limited terms to extend as long as 10, 15 or even 20 years.

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Long term certificates with pregranted abandonments have been held illegal in the Moss case (Moss v. FPC ____F.2d____; DC Cir. 1974).

Limited term certificates are a form of pregranted abandonment. In addition, limited term certificates are only justified under our emergency procedures. By definition, I do not believe limited term contemplates certificates of long duration. They can only be justified by our ability to predict the future public interest within reasonable limits as to the duration of the emergency. In Order 699-B itself, the majority stated, "We believe that these procedures should be reinstated with certain modifications in order that the interstate pipelines will be able to negotiate the additional short-term supplies of natural gas necessary to meet the demand for the 1974-5 winter season."

From that quote it appears their intent was clearly that

limited term certificates were meant to meet the needs of an immediate emergency and not as a device to avoid applying for long-term sales under standard certificating procedures.

While I have agreed that limited term agreements do have a place in providing better service during an emergency shortage, I also believe that they must, in fact, be limited in term to the coming year or at most, to the immediate and following winter. I also believe that limited term certificates should be granted in those cases where real proof is presented that there is a reason other than hopes for a higher future price to limit the duration of the contract. The stated reason for granting limited term certificates was to divert intrastate gas to the interstate market. Where there is no true diversion, but only the avoidance of a true commitment to interstate commerce, I do not believe we should approve such applications.

In addition, I would amend Opinion 699-B to provide that emergency term means what it says and will be granted for no longer than 18-month periods as a maximum.

[3623]

BIENNIAL REVIEW TO BEGIN JANUARY 1, 1975

Basically, I believe the 699 approach is valid in setting a national rate. On January 1, 1975, we will have the chance to make any needed changes in procedure or methodology. That is the time to begin any new pricing approach.

/s/ WILLIAM L. SPRINGER
William L. Springer
Commissioner

[3624]

OPINION NO. 699-H

Just And Reasonable National Rates for Sales of Natural Gas from Wells Commenced On or after January 1, 1973, And New Dedications Of Natural Gas to Interstate Commerce on or After January 1, 1973	Docket No. R-389-B

(December 4, 1974)

SMITH, Commissioner, *concurring in part* and *dissenting in part:*

I concur in the Opinion on Rehearing with the exception of the portion that grants the 699 rate to gas that is subject to expiring contracts. I dissent specifically and exclusively to the inclusion of those sales described in new Section 2.56a(2)(iii) (Opinion 699-H, p. 76) among sales eligible for the Base National Rate. I regard the determinations here made as to the type of gas eligible for the 699 rate as mutually independent,[1] each requiring independent support.

1. The framework established in Opinion No. 699 postulates the determination of a national rate for gas from wells commenced after January 1, 1973, and for gas first sold in interstate commerce after that date. The rate set purports to provide a fully adequate incentive for exploration, development, and production of new supplies. If the new gas rate provides adequate stimulation for new supply additions, then clearly no allowance of the new national rate for expiring contracts is justified. If the new nationwide rate in Opinion No. 699 is inadequate, then the remedy lies with adjustment of the nationwide rate level rather than in atoning for real or suspected inadequacies in that rate by granting the new price for the expiring contracts.

I. The Rate for "New" Gas

The discounted cash flow (DCF) analysis is an indispensable element in deriving a new gas rate that will be adequate to induce and compensate for the level of exploration and development that will be necessary to maintain the supply stability of interstate pipeline companies.

In contrast to the unadjusted *Permian I* formula, the DCF analysis here utilized results in the allowance of a return on the total investment in exploration and development, including dry hole costs. If a return on the dry hole portion of the investment is not allowed, the producer is required to write off these costs on a

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current-year basis against flowing-gas or other income. Unless such income was actually earned in that year, these costs must be written off as a loss. While most producers probably do and will continue to "expense" the exploration and development costs for tax purposes, it is patent that tax benefits are not the equivalent of actual income from the return on investment. Proper accounting for tax purposes is not necessarily proper accounting for ratemaking purposes.[2]

The effect of denying the return on the dry hole portion of exploration and development costs has been to favor large producers in the industry who have large and relatively stable quantities of flowing gas and to disfavor the smaller producers who likely have more erratic discovery and production patterns. Disadvantaged most by

2. *Alabama-Tennessee Natural Gas Co. v. F.P.C.*, 359 F.2d 318, 336 (5th Cir. 1966), *cert. denied*, 385 U.S. 847, *reh. denied*, 385 U.S. 964 (1966).

the approach is the new entrant who has no flowing gas to look to for the "expensing" of initial exploration and development costs and who must, therefore, absorb as a net loss the time value of the investment costs that cannot be expensed. The years of adherence to the methodology have, in my view, contributed significantly to concentration in the industry.[3] Finally, the *Permian I* approach offers even the large producers no incentive to increase exploration above the level that can be funded from the flowing gas allowance.

The Commission recognized at the outset that there might be something awry with the methodology. In the *Permian I* opinion it stated: "However, capitalization of E&D may well be a useful approach and we do not foreclose in succeeding cases further consideration of this alternative method of costing. . .".[4]

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Perhaps in an attempt to compensate for the inadequacies of the basic methodology, the Commission in *Permian I* included in the gas price a curious increment entitled "Adjustment for Exploration in Excess of Production." The purpose of this increment was said to be to "en-

3. Between 1962 and 1972, the 25 largest producers of natural gas for the interstate market increased their share of total sales by domestic producers to interstate pipelines from 70.9 percent to 76.7 percent and their share of total revenues from 73.1 percent to 78.2 percent. Producers selling less than 10 million Mcf a year to the interstate market accounted for 18.4 percent of total domestic sales to interstate pipelines in 1962 and 12.4 percent in 1972. (*Sales by Producers of Natural Gas to Interstate Pipeline Companies,* FPC, 1962 and 1972)

4. *Permian Basin Area Rate Proceeding,* 34 F.P.C. 159, 193 (1964), *affirmed, Permian Basin Area Rate Cases,* 390 U.S. 747 (1968).

courage a level of exploratory effort which will continue to provide for findings in excess of production."[5] However meritorious the allowance may have appeared, it was falsely premised in the context of new gas costing. The premise was that the *unit* cost of new gas production was greater because of the desired and anticipated overall increase in exploration and development expense. That premise was not proven and in fact probably was not true during the 1960's. As an increment to new gas revenues, the allowance was only a rather crude method of giving producers additional cash flow that presumably could be spent for additional exploration and development.[6] While the increment was imperfectly conceived and rationalized, the objective of stimulating a higher level of exploration and development was and is valid and is today all the more essential. The new gas price must fully cover the costs of finding new gas for it is only thereby that discrimination against new entrants and smaller producers can be avoided. Adherence to the unadjusted *Permian I* formula fails to achieve this objective. Adjusting the results obtained under that methodology by reference to the DCF analysis achieves a much more realistic cost-related incentive for producers to engage in expanded exploration and development.

The Opinion on Rehearing here issued properly recog-

5. *Ibid.* Subsequent events show that the allowance failed to achieve its purpose.

6. The increment was deleted from the costing methodology in the *Texas Gulf Coast Area* opinion. Area Rate Proceeding, et al. (Texas Gulf Coast Area), 45 F.P.C. 671 (1971), *reversed, Public Service Commission of the State of New York v. FPC,* 487 F.2d 1043 (D.C. Cir., 1973), *cert. granted, vacated and remanded, Shell Oil Co. v. Public Service Commission of the State of New York,* 42 U.S.L.W. 3686 (U.S. June 17, 1974).

nizes trends in establishing the major production cost factors, successful well costs and dry hole costs per foot. Statistical analysis estblishes a high correlation between the passage of time and cost per foot for successful wells and dry holes. The correlation coefficient between time and successful well costs for the past ten years is .98, and between time and dry hole costs for the same period is .95. Observation of general economic trends from 1972 to 1974 compels some adjustment of the 1972 data be made for the

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purposes of establishing 1973 and 1974 rates. Trending may not precisely predict the future, and in fact is likely to understate actual costs in a time of exceptionally high inflation. Also, there can be dispute about the series chosen to develop the trend. Nevertheless, actual data will not be available hereafter for years for which rates are set in this nationwide rate series and reasonable cost adjustments must be made. Trending by regression analysis is a sound method of adjusting actual data within a reasonable tolerance.

II. The Rate for "Flowing" Gas

A. Applicability of the Rate Established in Biennial Reviews

I concur that it is proper to provide that the prices established in the biennial reviews will be applicable to the gas that is first delivered during the preceding biennium. This is necessary to avoid the undesirable disruption in supply caused by speculation by the producer through suspension of drilling or withholding of supplies near the end of each biennium. However, at some time in

the indefinite future, if the cost increases continue, the disparity between new prices and old prices will be large enough to outweigh the desirability of suppressing end term speculation. At that time, only the new gas should be given the newly determined price. In other words, year-by-year or biennium-by-biennium "vintaging" is not per se a sound policy, but vintaging by cost groupings ultimately will become necessary to preclude the exaction of excessive and unjustifiable economic rent from flowing gas.

B. New Gas Rate for Contracts with Expired Primary Terms

The excessive and inadequately supervised economic rent and the discriminatory and anticompetitive impact cause my dissent to the portion of the Opinion that awards the new gas rate to flowing gas that is the subject of expiring contracts.[7] There are procedural issues raised by that application of this rate. Such a proposal was never noticed in conjunction with the R-389 proceeding. Further, a strong inference that R-389 would not deal with flowing gas can be derived from the notice in the R-478 proceeding which is stated to pertain to gas from "wells commenced before January 1, 1973."[8]

[3628]

In addition, I perceived and stated substantive reservations to that portion of the Opinion in my concurrence to the initial Opinion No. 699. The immediate cost to the consumer is not balanced by an assured or even demon-

7. §2.56a(a)(2)(iii), Opinion No. 699-H, at p. 76.

8. Nationwide rulemaking to Establish Just and Reasonable Rates for Natural Gas Produced From Wells Commenced Before January 1, 1973, Docket No. R-478, (May 13, 1973).

strably likely future benefit. A more detailed analysis of the contracts on file with the Commission in the R-478 proceeding reveals that the aggregate cost to the consumer through 1981 could reach $2.6 billion[9] and that analysis does not take account of any price increases that might be determined in future biennial reviews. The granting of the price increase to flowing gas is highly discriminatory to new entrants in the industry who enter with an unwarranted competitive disadvantage. Further, it is highly discriminatory among existing members of the industry. An analysis of the contracts on file with the Commission in the R-478 proceeding shows that the incidence of volumes under contracts expiring between 1972 and 1980 varies widely between producers.[10] For some producers, 100% of the 1972 volumes are subject to contracts that will expire before 1980. For other producers, less than 10% of the 1972 volumes would be eligible for the new gas rate prior to 1980. The other producers are spaced widely between the extremes. Such varying impact reinforces my view that the allowance of the new gas rate to expiring contracts is not a reasonable method of providing internal financing for producers nor is it consistent with the public interest.

Finally, Opinion 699 rejected the DCF analysis in part because the increase in flowing gas could make up inadequacy of the return element in the basic new gas rate.[11] However, the adoption of the DCF analysis in the present Opinion places new gas costing on an independent footing and that justification for increasing the flowing gas price

9. See Appendix A.

10. See Appendix B.

11. Opinion 699, pp. 89-90 (June 21, 1974).

to existing producers in this proceeding thus is no longer present.

I would approve an increase in flowing gas to the rates established in this proceeding only if preceded by public notice and subject to a plan and conditions that would improve the bargaining position of the interstate pipelines for on-shore gas. The interstate pipelines are rapidly losing ground to an intrastate market on on-shore areas, a fact that is not surprising in view of intrastate market price for new gas substantially higher than that price allowed for interstate purchases. The Commission should consider a plan allowing a producer to escalate the price of flowing gas sold to a given pipeline to the 699 rate to the extent

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of one, or possibly two, Mcf of flowing gas for each Mcf of new gas that is sold to pipeline buyers from on-shore areas under a new contract each year. Such a plan might slow down, although probably not reverse, the negative trend in on-shore dedications to the interstate market. If the flowing gas escalations were so conditioned, the consumer would at least have the assurance that an increase in price being paid for flowing gas was compensated for in the form of a new supply from the on-shore area. Such an escalation program is not free from difficulty or discrimination but I tentatively believe it to be far more consistent with the public interest than the unconditional price increase in flowing gas that is granted by the Majority.

The awarding of the 699 rate to the gas that is subject to expiring contracts sets the pricing system on a course that, if followed by future Commissions, would eliminate

vintaging for all gas except that which is subject to life-of-lease or reservoir contracts. In affirming the Commission's Opinion 639, the Fifth Circuit Court of Appeals forewarned:

> "We do not reach the question of whether the FPC may altogether discontinue the use of vintaging. Rather in each future order the Commission must continue to produce substantial evidence to support each essential element of the proposed rate structure. In Re Permian Basin Area Rate Cases, *supra*. Certainly the absence or presence of vintaging must be regarded as an essential element."[12]

I do not find substantial evidence that supports the nationwide, albeit gradual, discontinuance of vintaging that is herein approved by the Majority.

/s/ DON S. SMITH
Don S. Smith,
Commissioner

12. *Shell Oil Co. v. F.P.C.*, 491 F.2d 89-90 (5th Cir., 1974).

Appendix A

SUMMARY OF ESTIMATED INCREASED REVENUE IMPACT OF OPINION NO. 699
BY ALLOWING THE NEW GAS RATE FOR CONTRACTS WHOSE PRIMARY TERM EXPIRES

Year	First Eligible in Prior Years on Full Year Basis		First Eligible in Current Year on Full Year Basis		Total Volume 1/	Total Revenue 2/	
	Volume 1/	Revenue 2/	Volume 1/	Revenue 2/		Annual	Cumulative
1974			381	127.2	381	127.2	127.2
1975	323	111.3	175	61.7	499	173.0	300.2
1976	425	152.1	120	43.1	545	195.2	495.4
1977	463	170.8	285	100.9	748	271.7	767.1
1978	636	238.0	282	107.1	918	345.1	1,112.2
1979	778	300.7	347	130.7	1,125	431.4	1,543.6
1980	958	377.7	383	143.5	1,342	521.2	2,064.8
1981	1,140	455.6	261	105.1	1,402	560.7	2,625.5

1/ Billion Cubic Feet 2/ Millions of Dollars

NOTE:
1. Volumes represent an expansion of volumes reported to an estimated 100%.
2. Volumes for 1974 and subsequent years reflect an assumed 15% per annum decline in deliverability.
3. The assumed base rates reflect weighted average tax inclusive ceiling rates with 1.0¢ annual escalation.

SOURCE: Docket No. R-478; Questionnaire Schedule No. 5.

Appendix B

PERCENTAGE OF REPORTED 1972 SALES VOLUME
UNDER CONTRACTS WHOSE PRIMARY TERM WILL EXPIRE THROUGH 1980

Fifty Companies For Which Data Are Available

Producer	Reported 1972 Volumes Mcf	Volumes Under Contracts Expiring Through 1980	
		Volumes Mcf	Percentage of 1972 Volumes %
Amerada Hess	63,485,059	24,167,887	38.069
Amoco Production	952,954,209	313,344,463	32.881
Atlantic Richfield	700,141,841	293,711,390	41.950
Austral Oil	37,428,766	3,048,805	8.146
Aztec Oil & Gas	34,552,170	21,504,000	62.236
Belco Petroleum	25,355,527	23,524,354	92.817
Beta Development	5,570,178	5,520,178	100.000
Champlin Petroleum	119,169,504	78,723,089	66.060
Chevron Oil	46,752,951	21,447,009	45.873
Cities Service Oil	361,732,338	100,963,152	27.911
Clinton Oil	17,019,943	5,919,877	34.782
Coltexo Corp.	2,995,682	2,291,916	76.507
Continental Oil	447,149,053	221,401,009	49.514
Diamond Shamrock Corp.	73,007,874	5,357,447	7.338
Exchange Oil & Gas	21,375,951	723,789	3.386
Exxon Corp.	1,172,988,649	466,460,824	39.767
General American Oil	83,513,440	38,259,227	45.512
Getty Oil	330,760,251	218,224,473	65.977
Gulf Oil	718,923,410	166,722,685	23.191
Helmerich & Payne	11,410,776	1,068,751	9.366
Hassie Hunt Trust	18,236,327	5,288,432	28.999
Hunt Oil	45,557,544	4,812,684	10.564
Kerr-McGee Corp.	147,549,256	43,210,163	29.285
LVO Corp.	10,785,271	103,007	1.001
Lone Star Producing	17,194,279	3,574,117	20.787
Louisiana Land & Explor.	51,574,132	3,731,728	7.236
MAPCO, Inc.	19,417,787	2,194,729	11.303
Marathon Oil	92,500,461	26,606,648	28.764
Mobil Oil	616,510,689	96,144,964	15.595
Monsanto Co.	64,598,922	34,515,415	53.430
Northern Natural Gas Prod.	56,622,983	406,192	0.717
Pennzoil Producing	165,005,765	68,171,178	41.314
Placid Oil	41,128,027	14,464,107	35.168
Pubco Petroleum	11,594,463	8,021,242	69.182
River Corp.	8,864,487	7,860,567	88.675
Shell Oil	654,146,923	205,738,729	31.451
Sohio Petroleum	58,447,856	13,241,579	22.655
Southern Natural Gas Co.	14,725,463	1,184,200	8.042
Southern Natural, jt. ven.	14,970,204	14,970,204	100.000
Stephens Production	6,422,222	5,286,561	82.317
Sun Oil	296,497,642	119,791,628	40.402
Superior Oil	250,307,281	113,832,085	45.477
Sylvania Corp.	2,122,476	890,481	41.955
Tenneco Oil	14,615,826	4,205,176	28.771
Terra Resources	11,082,811	3,323,834	29.991
Texaco, Inc.	567,583,743	119,861,819	21.118
Texas Gas Exploration	35,444,182	1,988,888	5.611
Texas Oil & Gas	12,246,306	1,946,582	15.895
Trans Ocean Oil	20,456,550	6,569,238	32.113
Warren Petroleum	90,351,365	15,932,448	17.634
TOTAL REPORTED	8,642,848,815	2,960,318,010	34.251

SOURCE: Docket No. R-478, Questionnaire Schedule No. 5

[3632]

Just And Reasonable National Rates For Sales of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973	)	Docket No. R-389-B

(December 4, 1974)

MOODY, Commissioner, *dissenting:*

I dissent to the prescription of a rate which will have no more effect than the application of a bandaid to a severed jugular vein.

I.

While I am gratified that some of my views on cost-trending[1] and true yield analysis[2] have now achieved majority acceptance, with a resultant admission by the

1. See my dissent to Opinion No. 699, at pp. 10-21. I there argued for trending of cost components in order to achieve a more rational relationship between future cost levels and a rate designed for future applicability. The majority now concedes that trending of drilling costs, successful and dry hole, is both appropriate and necessary. The majority still refuses, however, to acknowledge that the lease acquisition cost component assigned in a 50¢/Mcf rate bears no relationship whatsoever to the record before us.

2. In my dissent to Opinion No. 699, at pp. 34-43, I advanced the belief that a failure to provide a return on total invested capital precluded the producer from earning the rate of return found to be essential to a viable enterprise. The majority's acceptance of DCF analysis recognizes the validity of this criticism. The method of DCF analysis displayed here—as to timing and tax assumptions—can no doubt be improved and refined, and our next national rate proceeding will unquestionably benefit from specific comments in this regard.

majority that it understated costs[2a] by at least 20 percent in Opinion No. 699, the fundamental error, of setting a rate level

which will not return costs and which ignores noncost considerations, remains.

I do not suggest that recognition of a 20 percent error in costing is insignificant, nor do I pretend that a recalculation of rates to move from 42¢/Mcf to 50¢/Mcf will not achieve some good results. The consumer will benefit from the larger number of offshore gas prospects that are made economically accessible by a higher rate. No, Opinion No. 699-H is much superior to Opinion No. 699.

Having said this, however, and having commended the majority for correction of two of the more egregious errors of Opinion No. 699, it is still incumbent upon me to say that Opinion No. 699-H fails to establish a just and reasonable rate.[3] The interstate consumer, already deprived of a reliable and adequate supply of natural gas

2a. I use "costs" in the same context as the majority. It should always be borne in mind, however, that the Commission does not determine actual costs for any producer or for any sale. To the contrary, the Commission develops a hypothetical rate base, hypothetical costs, and a hypothetical rate of return on the basis of industry-wide averages.

3. The rate prescribed by the majority is still predicated on the assumptions—wholly unsupported by the record—that 1973-1974 costs will, in total, drop below the level of the preceeding four years, and that 1973-1974 productivity will exceed that of the previous four years. The legal infirmities of ratemaking based on fantasy and not on fact were discussed at pp. 2-34 of my original dissent. There is no reason to alter my assessment of the record, or to restate my views. I stand on the dissent as written, for a 50¢ rate is no less subject to attack than a 42¢ rate on the basis of the record.

in most sections of the country,[4] will not be given succor by a 50¢ rate, nor will that rate greatly lessen the economic disruptions inherent in curtailment of pipeline service.[5] The gas shortage is a grievous wound inflicted on the economic life

of America by this Commission; to heal that wound, far more than the majority's action is demanded.

II.

The majority's rate prescription, judged by the standards of traditional costing methodology and without regard to modifications or improvements in that methodology, continues to understate producer costs. The 50¢/Mcf rate will not return the costs reasonably to be anticipated for the 1973-1974 biennium.

The errors which remain are holdovers from Opinion No. 699. I refer, of course, to the majority's continued refusal to follow the undisputed record before us with respect to productivity and an allowance for income tax expense.

4. During September, 1973, through August, 1974, nineteen interstate pipelines were forced to curtail their firm customers a total of 1.361 trillion cubic feet. See FPC News Release No. 20849, issued November 15, 1974, summarizing BNG study of curtailments.

5. The District of Columbia Court of Appeals has recently written a graphic description of the havoc wreaked by pipeline curtailment on one system where the curtailment level is approaching 28 percent. See *per curiam* slip opinion issued November 26, 1974, in No. 73-1999 *Consolidated (Ediscon) Co. of N.Y. v. F.P.C.* The situation on the *Transco* system there dealt with will be repeated on other systems as the shortage deepens.

Both issues were fully addressed in my original dissent,[6] and there is no reason to repeat what was there stated. I adhere to the view that a prediction of productivity which cannot be supported by the record evidence renders the rate based thereon unlawful.

In addition, however, to the matters discussed in the original dissent, the means are at hand to demonstrate the original dissent, the means are at hand to demonstrate the error of the majority. Since Opinion No. 699 was issued on June 21, 1974, the results of gas well drilling for calendar year 1973 have become available.[7] We now know that in 1973 the following occurred:

Successful Gas Well Footage (World Oil)	32,973,994
Successful Gas Well Footage (AAPG)	35,587,012
Total Gas Reserves Added	3,716,930 MMcf

Thus the productivity *actually experienced* in 1973 was:

113 Mcf/ft. based on World Oil reported footage
104.4 Mcf/ft. based on AAPG reported footage

[3635]

While Opinion No. 699-H continues to reflect a productivity prediction of 485 Mcf/ft. as the basis of 1973-1974 rates, it is now tragically clear that my dissent has been proven to be correct. 485 Mcf/ft. is not a rational prediction based on evidence and it cannot stand.

While I can understand, and sympathize with, the natural human reluctance of my colleagues to admit error

6. See dissent, pp. 5-10, 13-29, and 29-33 for discussion of these specific issues. As already noted in footnote 3, *supra*, the movement from 42¢/Mcf to 50¢/Mcf does not resolve the basic problem of a rate based on assumptions and estimates not supported by the record.

7. See Table I attached by the majority to Opinion No. 699-H.

in yet a third respect, thereby further validating the original dissent to Opinion No. 699, I think it irresponsible for the majority to ignore 1973 results and pretend that they are not now of record. At the very least, if the majority is to adhere to a seven-year averaging technique for predicting productivity, they should include the most recent year's results in their calculations.

Why do they not, Simply because this one change—and this only serves to underscore the sensitivity of the productivity prediction—drastically alters the cost estimates underlying the majority's 50¢/Mcf rate. A simple change, to substitute 1973 productivity for 1966 productivity, is *necessary* to the majority's theory that the average of the most recent seven years is the most reliable means of predicting the next two years' productivity; if this change is made, it is clear that a 50¢ rate *will not return costs.*

I have labored at comprehension of the reasoning set forth at pp. 19-26 of Opinion No. 699-H wherein the majority tries to justify setting a rate for 1973-1974 on the assumption that a six-year trend in declining productivity will be suddenly reversed. I glean that the majority believes that recently expanded drilling efforts will add greater reserves and that, therefore, anticipation of higher productivity is reasonable. I submit that this reasoning will not hold water. First, 1973 was one of those expanded drilling years that the majority is looking to for new reserves. But 1973 drilling resulted in the lowest productivity on record. *Secondly*, more drilling may reasonably be expected to produce additional reserves, but productivity does not increase unless the *ratio* of reserve additions to drilling increases. The greater the footage drilled,

the more reserves are needed to hold productivity constant. The majority's conclusion that greater drilling efforts necessarily presages an improvement in reserves added per foot drilled is simplistic; it is nothing more than wishful thinking insofar as the record before us is concerned.

[3636]

The perpetuation of demonstrable flaws in the majority's cost-estimation analysis[8] present a court with a traditional problem of judicial review of administrative action. In contrast, the majority's continued refusal to assess the effects of its rate order, and measure the legality thereof in terms of supply and demand consequences, presents the same type of problem faced by the Fifth Circuit in reviewing *SoLa I*.[9] The Court there saw what the Commission did not—that the mechanical application of cost-estimation formulae in natural gas pricing was resulting in the constriction of supply, to the detriment of consumer and producer alike.

Following *Austral's* insistence that the Commission weigh more carefully the effects of its rate orders, the Commission made a modest turn to incentive ratemaking.

8. In my original dissent I sought only to show that the majority had no substantial evidence support for its rate, even assuming the legality and propriety of the cost estimation—rate setting methods followed. Part II, *supra,* of this dissent pursues the same approach.

9. See 40 FPC 530 (1968)—the first area rate decision for *Southern Louisiana.* On appeal, in *Austral Oil Co. v. F.P.C.*, 428 F.2d 407 (CA 5, 1970), cert. denied, 400 U.S. 950 (1970), the Court faced squarely the Commission's failure to give adequate consideration to the effects of its order, and while affirming the Commission, did so in language unmistakable: The Commission had failed in its responsibilities.

In *SoLa II,*[10] *Other Southwest,*[11] and *Texas Gulf Coast,*[12] noncost factors were considered and utilized. Despite vociferous attacks, the Commission was upheld in doing so.[13]

[3637]

Now, however, when it is more critical than ever that the Commission fulfill its statutory duty to call forth adequate, reliable gas supplies, the majority has retreated into the shell of 100 percent cost based rates. The ratemaking tools necessary to combat the gas shortage have been discarded.

The majority's Opinion on Rehearing is the legal equivalent of a final denial by the Commission of any responsibility for whether or not its rate order will permit the movement of adequate and reliable supplies of gas to the interstate market. I believe this abdication of responsibility is correctable upon judicial review.

It is my hope that the Courts reviewing this order will speak definitively on the powers—and duties—of the Commission to set rates reasonably calculated to bring to interstate gas consumers a reliable and adequate supply of natural gas. For my own part, I believe that is the mandate already issued to the Commission by the Act and by judicial interpretation thereof.[14] But a majority of

10. Opinion No. 598, 46 FPC 86 (1971).

11. Opinion No. 607, 46 FPC 900 (1971).

12. Opinion No. 595, 45 FPC 674 (1971).

13. *Mobil Oil v. F.P.C.*, 42 U.S.L.W. 4842 (June 10, 1974); *Shell Oil Co. v. F.P.C.*, 484 F.2d 469 (CA 5, 1973), cert. denied 42 U.S. L.W. 3688 (1974).

14. See pp. 44-46 of my original dissent.

the Commission is of the unshakeable persuasion that rates exceeding cost estimates are unlawful—that, even though the devastating effects of cost-based rates on the consuming public are clearly identifiable, the Commission is powerless to do aught but perpetuate the underlying theory of *Permian I* ratemaking. These colleagues with whom I differ are men of good faith and men of intelligence. Perhaps they are right; perhaps the Courts fully intend to restrict rates to the level of costs plus return.[15] If so, then let it be said. Then at least we will know that the Commission should *not* worry about supply elicitation when it promulgates a rate order.

Though I realize it is presumptious, I ask that a reviewing Court speak to what is *required* of the Commission in the performance of producer ratemaking functions, and not what is permissible. Without specific direction, I have little hope that the Staff of the Commission, or a majority of the Commissioners, will do more than follow the politically popular course—of restricting rates to the level of estimated costs.

[3638]

In my original dissent to Opinion No. 699, I opined that a reviewing court would probably not compel major changes in the Commission's ratemaking theories. I have changed my views; if the Court does not now interpose its judgment, there is no realistic hope for the interstate gas consumer. What we have here is an agency which

15. Certainly the rationale of the Court in the *Texas Gulf Coast* appeal [see 487 F.2d 1043 (CADC, 1973)]; in the *Belco* appeal (see ____F.2d____, CADC 1974); and in the *George Mitchell* appeal (see ____F.2d____, CADC 1974) clearly indicates that one Court of Appeals believes producer costs are the be-all and end-all of ratemaking.

believes itself so fettered by the *City of Detroit*[16] dictum concerning costs that it issues an order which it knows cannot significantly lessen the gas shortage. Judicial direction is absolutely imperative if gas consumers are to be protected.

IV

I file this dissent—overlong and didactic as it is—because of a sense of profound concern for the present, and future, of the gas consumer dependent on the interstate pipelines. I attempt hereby to bring to the attention of the reviewing Court the message of catastrophe which current figures portend.

The basic data is known to us all:

1963-1973 DOMESTIC RESERVES, PRODUCTION AND PURCHASES OF MAJOR GAS SUPPLY COMPANIES[1] (From Form 15 Reports)

Year	Number of Companies	Annual Production and Purchases	Year End Gas Reserves
1963	24	9.0	184.6
1964	24	9.7	185.0
1965	23	10.0	187.6
1966	24	10.8	190.0
1967	24	11.5	194.1
1968	24	12.2	191.3
1969	24	13.1	184.2
1970	25	13.8	170.1
1971	25	13.9	158.1
1972	25	13.9	144.2
1973	25	13.4	131.9

(1) Major companies are those having over 900 billion cubic feet of domestic in-the-ground reserves at the inception of the Form 15 resport or date of first filing of the form.

16. *City of Detroit v. F.P.C.*, 230 F.2d 810 (1955), cert. denied 352 U.S. 829 (1956).

[3639]

The pattern of near-constant production and declining year-end reserves occurs because new reserves are not being added at a sufficient rate to offset deliverability declines from old reservoirs. The pattern of reserve additions compared to natural gas production is set forth below:

Reserves, Production, and Reserve Additions of Interstate Pipelines Form 15 Data (Lower 48 States) (Volumes in Trillions of Cubic Feet)

	End of Year Reserves	Net Production	Net Reserve Additions
1963	188.5	9.4	N/A
1964	189.2	10.0	10.7
1965	192.1	10.4	13.3
1966	195.1	11.1	14.1
1967	198.1	11.8	14.8
1968	195.0	12.6	9.5
1969	187.6	13.4	6.1
1970	173.6	14.1	0.04
1971	161.3	14.2	1.9
1972	146.9	14.2	(0.2)
1973	134.3	13.7	1.1

Thus, for six consecutive years, the interstate system has eaten away at existing reserves. The inventory is fast disappearing from the shelf, as indeed it must when production consistently exceeds new reserve additions. What is being consumed is not being replaced.

For a few years, inventory consumption can be tolerated without significant impact. But we have had those few years. They are behind us. The repeated failure to balance new supply and production has taken its toll, and we now see the vast majority of the pipelines unable to meet the needs of their customers. Thus we find:

Comparison of Actual Firm Requirements and Firm Curtailments For Year September 1973 Through August 1974 With Projections for Year September 1974 Through August 1975 (From BNG Report of November 15, 1974 -- See FPC News Release No. 20849)

Pipeline	Total For Year September 1973-August 1974 Firm Requirements (Mcf)	Actual Volume Curtailed (Mcf)	Percent Curtailed	Total For Year September 1974-August 1975 Firm Requirements (Mcf)	Projected Deficiency (Mcf)	Percent Deficient
Alabama-Tennessee Natural Gas Company	26,558,000	-0-	-0-	29,863,000	-0-	-0-
Algonquin Gas Transmission Company	160,595,000	10,475,000	6.51	162,648,000	12,205,000	7.50
Arkansas Louisiana Gas Company	535,062,000	162,018,000	30.28	538,692,000	157,302,000	29.20
Cities Service Gas Company	561,668,000	49,187,000	8.76	577,183,000	131,319,000	22.75
Colorado Interstate Gas Company	369,430,000	69,000	0.02	370,300,000	-0-	-0-
Columbia Gas Transmission Corporation 1/	1,345,959,000	- - -		1,457,559,000	216,011,000	14.82
Commercial Pipeline Company, Inc.	373,000	-0-	-0-	401,000	-0-	-0-
Consolidated Gas Supply Corporation	704,628,000	-0-	-0-	779,492,000	43,756,000	5.61
East Tennessee Natural Gas Company	98,205,000	-0-	-0-	81,300,000	3,459,000	4.25
Eastern Shore Natural Gas Company	11,187,000	42,000	0.37	5/		
El Paso Natural Gas Company 2/	1,437,793,000	124,691,000	8.67	1,453,441,000	291,019,000	20.02
Florida Gas Transmission Company	28,521,000	-0-	-0-	38,940,000	-0-	-0-
Great Lakes Gas Transmission Company	415,806,000	-0-	-0-	424,970,000	-0-	-0-
Kansas-Nebraska Natural Gas Company	85,377,000	-0-	-0-	83,656,000	-0-	-0-
Kentucky-West Virginia Gas Company	26,522,000	-0-	-0-	27,858,000	-0-	-0-
Lawrenceburg Gas Transmission Corporation	5,414,000	-0-	-0-	5,475,000	-0-	-0-
Louisiana-Nevada Transit Company	4,813,000	56,000	1.16	4,787,000	523,000	10.93
McCulloch Interstate Gas Corporation	15,230,000	-0-	-0-	10,969,000	-0-	-0-
Michigan Wisconsin Pipe Line Company	935,356,000	-0-	-0-	937,562,000	-0-	-0-
Mid Louisiana Gas Company	31,225,000	-0-	-0-	32,572,000	4,226,000	12.97
Midwestern Gas Transmission Company	347,927,000	-0-	-0-	350,011,000	9,008,000	2.57
Mississippi River Transmission Corporation	202,898,000	2,466,000	1.22	210,316,000	926,000	0.44
Montana-Dakota Utilities Company	35,584,000	-0-	-0-	38,439,000	-0-	-0-
National Fuel Gas Supply Corporation 3/	99,752,000	-0-	-0-	167,436,000	-0-	-0-
Natural Gas Pipeline Company of America	1,192,732,000	213,133,000	17.87	1,204,529,000	216,479,000	17.97
North Penn Gas Company	28,573,000	-0-	-0-	29,834,000	-0-	-0-
Northern Natural Gas Company	817,516,000	8,547,000	1.05	815,698,000	5,885,000	0.72
Northwest Pipe Line Corporation 2/	246,923,000	11,230,000	4.55	453,588,000	40,738,000	8.98
Pacific Gas Transmission Company	402,964,000	-0-	-0-	415,845,000	-0-	-0-
Panhandle Eastern Pipeline Company	814,134,000	48,677,000	5.98	834,520,000	87,170,000	10.45
South Georgia Natural Gas Company	10,839,000	-0-	-0-	13,942,000	-0-	-0-
Southern Natural Gas Company	597,643,000	-0-	-0-	645,850,000	2,501,000	0.39
Tennessee Gas Pipeline Co., A Division of Tenneco, Inc. 4/	1,346,864,000	10,898,000	0.81	1,368,970,000	104,364,000	7.62
Tennessee Natural Gas Lines, Inc.	22,292,000	-0-	-0-	23,879,000	-0-	-0-
Texas Eastern Transmission Corporation	1,073,319,000	146,198,000	13.62	1,085,960,000	247,162,000	22.76
Texas Gas Pipe Line Corporation	4,377,000	-0-	-0-	2,129,000	-0-	-0-
Texas Gas Transmission Corporation	731,735,000	14,229,000	1.94	771,081,000	64,639,000	8.38
Transcontinental Gas Pipe Line Corporation	1,085,735,000	209,991,000	19.34	1,107,008,000	307,364,000	27.77
Transwestern Pipeline Company	365,017,000	24,616,000	6.74	366,852,000	98,875,000	26.95
Trunkline Gas Company	591,636,000	187,349,000	31.67	593,239,000	227,153,000	38.29
United Gas Pipe Line Company	1,563,743,000	552,582,000	35.34	1,608,438,000	704,350,000	43.79
Valley Gas Transmission, Inc.	16,183,000	-0-	-0-	N/A		
West Texas Gathering Company	95,693,000	-0-	-0-	92,285,000	-0-	-0-
Western Gas Interstate Company	7,250,000	-0-	-0-	8,708,000	73,000	0.84
Totals	18,501,446,000	1,776,454,000	9.60	19,226,225,000	2,976,507,000	15.86
Less: Pipeline to pipeline curtailments		414,583,000			618,402,000	
Net Curtailments		1,361,871,000			2,358,105,000	

1/ Columbia Gas Transmission Corporation states that during the period November 1973 through March 1974, it imposed a 2% curtailment on all CD, WS and G customers, however, due to warmer then normal weather, energy conservation, etc., actual curtailment cannot be ascertained.
2/ On January 31, 1974, El Paso divested its Northwest Division System properties to Northwest Pipeline Corporation. Northwest has filed actual data for February through August 1974. El Paso has reported the actual data for the period September 1973 through January 1974.
3/ National Fuel Gas Supply Corporation formerly United Natural Gas Company.
4/ Firm curtailments were added to firm deliveries to arrive at firm requirements in the September 30, 1974 report.
5/ Eastern Shore Natural Gas Company is uncertain about the curtailment by Transcontinental Gas Pipe Line Corporation to Eastern Shore, whether it will be 22% or 35%. It did not submit estimates for the projected period September 1974-August 1975.

N/A Not Available

The foregoing tabulation relates to curtailments of firm customers; as might be expected, interruptible customers have fared even worse, and can expect curtailments of 58.24 percent next year:

Comparison of Actual Interruptible Sales and Curtailments
For Year September 1973-August 1974 with Projected
Requirements and Deficiencies for Year
September 1974-August 1975
(From BNG Report of November 15, 1974 -- See FPC News
Release No. 20849)

	Actual*			Projected**		
	Interruptible Requirement (MMcf)	Volume Curtailed (MMcf)	% Curtailed	Interruptible Requirement (MMcf)	Volume Deficiency (MMcf)	% Deficient
Alabama-Tennessee	14,996	3,222	21.48	16,472	3,569	21.66
Algonquin Gas	10,452	10,452	100.00	13,131	13,131	100.00
Arkansas Louisiana	13,434	13,434	100.00	19,868	19,868	100.00
Colorado Interstate	49,305	18,363	37.24	60,865	33,925	55.74
East Tennessee	22,759	-0-	-0-	25,455	23,673	92.99
Eastern Shore	1,955	1,689	86.39	(2)		
El Paso (1)	-0-	-0-	-0-	-0-	-0-	-0-
Florida Gas	132,640	39,968	30.13	134,723	73,233	54.36
Kansas-Nebraska	32,546	-0-	-0-	30,390	1,350	4.44
Louisiana-Nevada	1,841	3	0.20	6,243	2,972	47.61
Mississippi River	35,365	26,611	75.25	-0-	-0-	-0-
Montana-Dakota	21,220	256	1.21	21,145	330	1.56
Northern Natural	11,179	-0-	-0-	2,345	-0-	-0-
Northwest Pipeline (1)	14,778	5,949	40.26	26,991	24,654	91.34
Panhandle Eastern	69,851	14,692	21.03	65,087	26,705	41.03
South Georgia	29,604	13,403	45.27	29,602	17,263	58.32
Southern Natural	168,537	97,746	57.99	126,095	101,402	80.42
Tennessee Natural	14,354	1,783	12.42	15,353	2,878	18.74
Texas Gas	4,058	-0-	-0-	4,080	3,877	95.02
Transwestern	1,050	-0-	-0-	1,050	-0-	-0-
TOTALS	649,894	247,571	38.09	598,895	348,830	58.24
Less: Pipeline to Pipeline Curtailments		29,262			82,625	
NET CURTAILMENTS		218,309			266,205	

*Year September 1973-August 1974
**Year September 1974-August 1975

(1) On **January 31, 1974, El Paso** divested its Northwest Division System properties to Northwest Pipeline. Northwest has filed actual data for February through August 1974. El Paso has reported the actual data for the period September 1973 through January 1974.

(2) Eastern Shore is uncertain about the curtailment by Transcontinental to Eastern Shore, whether it will be 22% or 35%. It did not submit estimates for the projected period September 1974-August 1975.

Massive curtailments by the interstate pipelines were inevitable, of course, once it became clear that the pipelines were unable to attach sufficient new reserves to offset normal depletion of old reserves. The deteriorating supply position of the pipelines is fully documented by reviewing the applicable Form 15 data filed with us annually. Over the past ten years we see that the pipelines began 1964 with 184.8 Tcf in reserves:

	Reserves	Annual Production	GC/P Ratio
1963 (Year-End)	188.5		
1964 Reserve Changes	+ 10.640	10.014	1.06
1965	+ 13.282	10.370	1.28
1966	+ 14.190	11.137	1.27
1967	+ 14.751	11.820	1.25
1968	+ 9.453	12.552	0.75
1969	+ 6.081	13.433	0.45
1970	+ 0.038	14.092	0.00
1971	+ 1.991	14.205	0.14
1972	- 0.229	14.207	0.02
1973	+ 1.092	13.680	0.08
1973 Year-End	134.3		

Over this ten-year span, the pipelines' gross change in reserves was -52.7 Tcf -- a drop of almost 30 percent -- because of the extent to which production outstripped positive reserve changes. A GC/P Ratio of 1 tells us that the pipelines are holding a constant reserve position; a ratio greater than 1 indicates an improvement in supply, while a ratio of less than 1 warns of supply deterioration. For the past ten years, our major pipelines experienced a GC/P ratio of only .57.

As indicated, all of the foregoing relate to the known past. These figures do no more than tell us what all responsible observers of the natural gas situation have fully recognized -- that there is a shortage of crisis proportions which is already inflicting a heavy toll on the economic well-being of the United States.

But what of the immediate future? I am convinced that the crisis has only begun; that, if today's order is not quickly reviewed and quickly corrected, the current level of economic disruption will be but a shadow of what lies ahead. The handwriting on the wall for the future is reasonably clear.

Reserve to production ratios give a gross estimate of the number of years that presently committed reserves will serve the market. While, in my judgment, a composite R/P ratio tends to mask the problems of individual pipelines, a declining trend in the national R/P ratio provides some insight into future problems. Accordingly:

R/P RATIOS

	Form 15	
	Major Co's. 1/	All Co's.
1965	18.7	18.5
1966	17.7	17.5
1967	16.9	16.8
1968	15.6	15.5
1969	14.0	14.0
1970	12.3	12.3
1971	11.5	11.5
1972	10.4	10.3
1973	9.8	9.8

1/ Pipeline companies whose in-the-ground reserves, company owned and contracted from Independent Producers, are in excess of 900 million Mcf (900 billion cubic feet).

Of far greater significance are the deliverability studies which we require of the pipelines on an annual basis as part of the Form 15 filings. These studies express the pipelines' best judgment as to future deliverability of presently attached reserves. The figures are shocking.

COMPARISONS OF COMPOSITE 5-YEAR DELIVERABILITY PROJECTIONS
FROM YEAR END DEDICATED DOMESTIC GAS RESERVES
(BILLION CUBIC FEET AT 14.73 Psia @ 60°F.)

DATE OF ESTIMATE	1969	1970	1971	1972	1973
YEAR END RESERVES 1/	187,609	173,556	161,341	146,906	134,317
YEARS	Annual Volumes Scheduled 2/				
1969	*13,433				
1970	13,872	*14,092			
1971	13,929	14,281	*14,205		
1972	13,814	14,170	13,743	*14,207	
1973	13,651	13,863	13,287	13,633	*13,680
1974	13,350	13,258	12,738	12,907	13,062
1975		12,469	12,054	12,007	12,346
1976			11,360	10,984	10,980
1977				10,029	9,993
1978					9,002
Five-Year Total	68,616	68,041	63,182	59,560	55,383
Percent of Year End Reserves	36.6	39.2	39.2	40.5	41.2

* Actual volumes purchased and/or produced.

1/ 1971, 1972, and 1973 data includes reported emergency purchases.

2/ Annual volumes scheduled prior to 1972 estimates do not include companies with less then 50 billion cubic feet of in-the-ground reserves who, prior to 1972 were not required to file deliverability estimates.

A drastic drop off in deliveries from presently attached reserves is imminent. The magnitude of the deliverability decline can perhaps best be appreciated by analyzing the decline in percentage terms:

DELIVERABILITY COMPARISONS 1968-1973
All Companies Reporting on Form 15 [1]

DATE OF ESTIMATE	1968	1969	1970	1971	1972	1973
Largest Volume Scheduled [2] (Billion Cubic Feet)	13,345	13,929	14,281	13,743	13,633	13,062
Year	Percent Decline From Largest Volume					
2	0.0	0.0	0.8	3.5	5.3	5.5
3	1.0	0.8	3.2	7.3	11.9*	15.9*
4	2.2	2.0	7.7	12.4*	19.4	23.5
5	3.4	4.2	12.7*	17.4	26.4	31.1
6	5.8	7.6	18.2	22.6		
7	8.7	12.7*	24.2	28.2		
8	11.7*	18.0	29.2	35.6		
9	15.9	24.4	37.4	43.2		
10	21.7	33.3	45.0	49.5		
11	29.4	41.2	51.7	60.5		
12	37.3	48.6	57.6	65.0		
13	45.7	55.5	63.3	68.8		
14	53.5	61.4	68.2	73.8		

* Year 10 percent occurs.

[1] Excludes companies with less than 50 billion cubic feet of in-the-ground gas reserves for years 1968 through 1971.

[2] First year volumes with exception of 1968-1969 which are second year volumes.

[3646]

At current production levels, national curtailment is in the range of 15 percent. When production from currently attached reserves drops by 45 percent in only five years, the level of curtailment may well be too great for survival of the gas industry.

Leaving aside questions of what this supply decline will do to these former gas consumers who can no longer be served, at any price, the rate impact of declining deliveries on these consumers who continue to receive service will, in my judgment, be totally unacceptable to this nation. Even if we assume no increase in pipeline fixed costs over the next five years, and even if we assume retention of present pipeline depreciation rates, those customers who receive gas in the future face unprecedented increases in pipeline rates—increases which may be predicted because reduced volumes require a higher rate per unit delivered to recover fixed costs. For a representative group of pipelines, the deliverability decline for each forecasts the following rate impact.

REPRESENTATIVE MAJOR PIPELINE COMPANIES

UNIT IMPACT UPON COST RECOVERY OF CHANGES IN SALES VOLUMES

Line	Company	C of S (1)	PROJECTED SALES VOLUMES BASED UPON DELIVERABILITY (2) 1974	1975	1976	1977	1978	UNIT COST RECOVERY PER MCF OF SALES 1974	1975	1976	1977	1978
		$ (000)	* * * * * * * *		(Tcf)	* * * * * * * *		* * * * * * * *		¢/Mcf	* * * * * * * *	
1	Columbia Gas	518,458	1.390	1.298	1.208	1.200	1.153	37.29	39.96	42.92	43.27	44.99
2	Consolidated	220,279	.648	.641	.646	.701	.660	33.98	34.37	34.08	31.43	33.39
3	El Paso (Divested)	368,651	1.248	1.088	.947	.860	.775	29.55	33.90	38.93	42.88	47.60
4	Florida Gas	66,455	.133	.125	.116	.107	.100	49.96	53.28	57.17	62.40	66.13
5	Mich-Wisc	281,181	.836	.837	.835	.835	.773	33.64	33.61	33.68	33.68	36.36
6	Natural	371,967	1.049	1.006	.931	.843	.779	35.45	36.96	39.95	44.11	47.76
7	Northern	298,848	.815	.747	.665	.607	.553	36.68	40.01	44.95	49.21	54.01
8	Panhandle	178,642	.649	.607	.566	.524	.490	27.54	29.45	31.56	34.08	36.48
9	Tennessee	440,800	1.301	1.312	1.211	1.101	1.004	33.88	33.61	36.40	40.02	43.90
10	Texas Eastern	377,033	.834	.786	.739	.717	.694	45.21	47.96	51.07	52.58	54.30
11	Texas Gas	158,515	.722	.686	.641	.608	.552	21.96	23.11	24.72	26.08	28.70
12	Transco	304,015	.773	.675	.577	.487	.411	39.32	45.07	52.66	62.40	73.89
13	Transwestern	82,498	.322	.278	.254	.232	.211	25.59	29.67	32.51	35.49	39.05
14	Trunkline	157,039	.419	.363	.346	.309	.272	37.50	43.29	45.39	50.80	57.82
15	United	153,266	.967	.835	.756	.662	.569	15.85	18.37	20.27	23.16	26.93

(1) Cost of Service data taken from latest rate increase filing and excludes variable costs, primarily purchased gas commodity costs.

(2) Sales volumes reflect deliverability projections adjusted for company use, lost and unaccounted for.

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To place in focus the potential rate impact of the present trend of gas supply deterioration, note these specifics:

	1974	1978
El Paso	29.55¢/Mcf	47.60¢/Mcf
Natural	35.45¢/Mcf	47.76¢/Mcf
Northern	36.68¢/Mcf	54.00¢/Mcf
Tennessee	33.87¢/Mcf	43.90¢/Mcf
Texas Eastern	45.21¢/Mcf	54.30¢/Mcf
Transco	39.32¢/Mcf	73.89¢/Mcf
Transwestern	25.59¢/Mcf	39.05¢/Mcf
United	15.85¢/Mcf	26.92¢/Mcf

These figures should be compared with the majority's analysis of the potential rate impact on consumers by reason of increased wellhead rates (Opinion, pp. 54-56). It appears that increased curtailment may well cause a higher rate to consumers (for less gas), than will an increase in the price paid to producers.

The short-range impact of the pipelines' inability to meet the needs of their customers has other consequences. I have set forth at page 9, *supra*, the anticipated level of curtailments for September 1974 - August 1975. These curtailments will cause a greater demand on oil and oil products, which, tragically, can be met only through increased imports of foreign oil and products. The fuels necessary to substitute for 2.3 Tcf of nonavailable natural gas will approximately 387 million barrels of #2 fuel oil. For the longer range, if the projected decline in deliverability of natural gas—causing curtailments far in excess of 2.3 Tcf—is considered, it would seem obvious that the future fuel bills of this country, and the increased dependence on imported oil, are totally unacceptable.

Current levels of curtailment, at a national average of approximately 15 percent, have proved enormously disruptive. If the present procurement activities of the interstate pipelines are no more productive than they have been, the sharply accelerating deliverability decline which presages curtailment levels of 30 percent or more within the next five years clearly predicts economic chaos and a total breakdown of the FPC's rationing efforts.

[3649]

V.

The majority's order will not prevent, nor materially lessen the grave consequences which lie ahead for the interstate gas consumer. I so conclude because of the unanimity of the parties before us in this proceeding who assert, without exception, that a rate based on costs alone —and falling within the range set by Opinion No. 699— will not permit the interstate pipeline to attach sufficient new reserves to reverse the trend of the past six years.

Pipelines and distributors alike now join the producng segment in analyzing the majority's rate order as ineffective. Even those parties not involved in buying and selling gas who say that a 42¢/Mcf rate is too high make their arguments only in the context of producer profit levels; none assert that interstate consumers will, in fact, gain substantial new supplies under the majority's rate order.

The record before us will not permit a reasonable man the luxury of belief that interstate pipelines can successfully contract for new onshore supplies of gas at the rate level set by the majority. What the majority has done is, for all practical purposes, set a rate for new offshore federal domain gas. Only those new supplies which must,

by operation of law,[17] move interstate will move into interstate commerce under the rate structure set forth in Opinion No. 699-H. Onshore gas, which can be sold free of the price restraints of our jurisdiction, and which can be marketed intrastate at a rate at least twice the FPC - set price, will not move into interstate commerce. This is a fact of life. The interstate pipelines have become increasingly unable to pick up onshore gas:

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ESTIMATED NEW LONG-TERM CONTRACT SALES BY LARGE PRODUCERS 1970-1973 OFFSHORE FEDERAL DOMAIN Vs. ALL AREAS (Million Mcf)[18]

Year	All Area (1) Sales	Sales Offshore (2)	Offshore Percent (2)	Sales Onshore	Onshore Percent
1970	302.6	73.3	24.2	229.3	75.8
1971	453.7	207.7	45.8	246.0	54.2
1972	474.3	279.4	58.9	194.9	41.1
1973	330.3	221.1	66.9	109.2	33.1

(1) FPC pricing areas and California (Federal domain)
(2) Federal domain areas offshore Louisiana, Texas and California.

This increased dependence of the pipelines on offshore purchases, or, to put it another way, the inability of the interstate pipelines to buy gas onshore, is attributable solely to the FPC rate structure which makes it impossible for the interstate pipelines to compete for new supplies.

As an adjunct to the problem of the interstate market becoming increasingly dependent on the offshore areas, it

17. See the *Ship Shoal* decision, *Continental Oil Co. v. F.P.C.*, 370 F.2d 57 (CA 5, 1966), cert. denied 388 U.S. 910 (1967).

18. Figures derived from applications filed with the Commission for new long-term sales certificates.

is critical to remember that several of our major pipelines (and therefore millions of consumers) have no means of access to the offshore area. These "land-locked" pipelines (such as El Paso, Transwestern, Northern, Ark-La, Cities Service and MRT), simply have no ready means of attaching offshore gas. They are virtually dependent on onshore gas.

While we continue to ignore the plight of the "land-locked" pipelines, and try to pretend that the interstate consumer can achieve reliable and adequate service through development of

[3651]

offshore reserves alone, it is manifest that the likelihood of this occurrence is less, day by day. I so conclude because of the following:[19]

	Total U. S. Gas Exploratory Footage (million feet)	Offshore Gas Exploratory Footage (million feet)	Offshore as Per centage of Total
1970	3.7	.26	7.0%
1971	3.3	.41	12.4%
1972	4.6	.14	3.0%
1973	6.2	.17	2.7%
1974 (1st half)	3.8	.08	2.1%

Less and less of the total U.S. gas exploratory effort is being directed offshore.

At the same time, the offshore development effort is slackening:

19. All figures taken from latest publication of "Gas Supply Indicators" by the FPC Office of Economics, issued October 25, 1974.

	Total U. S. Gas Development Footage (million feet)	Offshore Gas Development Footage	Offshore as Percentage of Total
1970	19.2	1.6	8.3%
1971	19.3	1.7	8.8%
1972	22.2	1.5	6.8%
1973	29.4	2.3	7.8%
1974 (1st half)	16.0	.97	6.1%

[3652]

These patterns are, I believe, directly attributable to the Commission's prescription of jurisdictional rates at levels far below those of the free market. The producing segment is demonstrating that investment decisions—as to where to drill—are responsive to price and profit considerations.

Thus, rate orders like Opinions No. 699 and No. 699-H do a double disservice to the interstate consumer—the rate precludes attachment of onshore supplies, and contemporaneously causes a decline in badly needed offshore exploration and development.

The loser through all this is, has been, and will continue to be, the interstate consumer. The Commission is, simply through the process of determining rates on the basis of historic average costs, simultaneously forestalling the procurement of new supplies already found, and precluding drilling for the future supplies which might solve the shortage.

VI.

Changing times and changing circumstances have cast too heavy a burden on cost-based wellhead ratemaking for it to survive.

From *Phillips,*[20] taken in conjunction with the *Ship Shoal*[21] decision, it follows that the rate at which a producer in the Federal domain offshore sells gas is controlled by the FPC, if the sale is a "sale for resale." It also follows from *Phillips* that the rate at which a gas producer onshore sells is controlled by the Commission, if he sells for resale in interstate commerce. If, however, the producer sells to the ultimate consumer, or if he sells in intrastate commerce, his sales rate is not subject to regulation by the Commission.

[3653]

It is critical to note that the Courts' construction of FPC jurisdiction does not extend FPC control to production activities or facilities as such; FPC jurisdiction attaches when an interstate sale for resale, or interstate transportation, commences. This means, most simply, that the Commission cannot compel a producer to explore, nor to develop, nor to deliver uncommitted gas to the interstate market. See *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968). In *F.P.C. v. Transcontinental Gas Pipeline Corp.,* 365 U.S. 1 (1961) the Supreme Court put it this way:

> ". . . it must be realized that the Commission's powers under § 7 (of the Natural Gas Act) are, by definition, limited. (Citation omitted.) The Commission cannot order a natural gas company to sell gas to users that it favors: (Footnote omitted) it can only exercise a veto power over proposed (interstate transactions) . . ." 365 U.S. at 17.

20. *Phillips Petroleum Co. v. Wisconsin,* 347 U.S. 672 (1954).

21. *Continental Oil Co. v. F.P.C., supra.*

Thus, it is through rate structure alone that the Commission must attempt to fulfill its statutory mandate with respect to maintenance of reliable and adequate supplies of natural gas. The Commission's rate must act as an incentive to the producer—to induce an affirmative investment decision to drill, in the first instance, and to induce the economic decision later to sell to the interstate market as opposed to the decision to hold for his own use or to sell in the intrastate market. See *Permian Basin Area Rate Cases, supra; Austral Oil v. F.P.C.,* 428 F.2d 407 (1970), cert. denied, 400 U.S. 950; *Placid Oil Co. v. F.P.C.,* 483 F.2d 880 (1973).

It has not been possible for the FPC to devise a rate structure capable of fulfilling all these functions and still adhere to cost-of-service rate making principles. Were it possible, we would not have the shortage which now threatens the national economy. For example, if, as was true in the 1960's, the rate set is at a level where the prudent operator finds it more advantageous to turn to alternate investment opportunities, wells will not be drilled. And, if, as has been true since 1969, the rate set is at a level where the prudent operator can realize a greater return by converting his product into petrochemicals or fertilizer, he will withdraw his gas from the energy market and devote it to other uses; or, as has

[3654]

also been true since 1970-1971, if the FPC rate is below that offered by intrastate purchasers, the prudent operator will sell to the intrastate market.

Rate decisions of this Commission have not, of course, been set to achieve deliberately the undesirable result of a gas shortage of critical dimensions. Rates have been set

as indicated by *City of Detroit*—based on estimated rate base, estimated costs, and estimated rate of return. The focus was always backward—towards the average of historic costs spent in a past test year—and never forward.

Such an approach can never achieve the multiple demands made on the FPC rate structure. Cost-based rates cannot call forth a gas well drilling investment when an oil well drilling investment is more promising. Cost-based rates cannot command interstate dedications when intrastate dedications are more attractive.

And so, we come to the crossroads again. Is the Commission to use rate to elicit drilling and dedication of new supplies to the interstate market? Or is the Commission to set rates based on costs alone? *Both objectives cannot be achieved.*

A majority of the present Commission has opted for continuation of cost-based ratemaking though they know as well as I that a rate so made cannot bring sufficient gas to the interstate market to alleviate the shortage.

We have reached the point in our nation's history that the fallacy of *Permian I* ratemaking, even as modified by Opinion No. 699-H, can no longer be countenanced. We have a structure which has not worked, and which cannot work.

The consumer deserves better. If this Commission will not correct that which is destroying the interstate market, then surely a reviewing court must.

VII.

Producer ratemaking, as practiced by the Commission since *Permian I*, is a snare and a delusion. It has the ap-

pearance, and the stated purpose, of guarding consumers against the

[3655]

extortion of excessive profits by gas producers. But it has the inevitable effect of sealing off from exploration and development all but the most profitable drilling opportunities.

What occurs after an FPC rate, based on average costs, is announced? Common sense tells me that gas producers begin to measure their drilling prospects in terms of profitability. If a particular drilling prospect will be profitability at the FPC-set rate level, it will be drilled; if the economics of the venture indicate that profitability is not reasonably to be expected, the prospect is not drilled. I do not believe that any reasonably prudent operator will drill when his own best estimates of costs, and productivity, tell him that if he finds gas he can sell it only at a loss. Thus, an FPC rate is, in practical effect, a ceiling on what gas wells are drilled—but it is not a ceiling on profits.

For the long run, average cost based ratemaking guarantees a decline in exploration. Once the rate is announced, drilling operations tend to limit themselves to the average and below average cost prospect. Ironically, this process tends to maximize the profits on the fewer and fewer prospects drilled, while at the same time limiting the exploration and development of high risk, high cost prospects.

In a time of apparent plenty, this process raised few eyebrows. But now, when the need for additional supplies

has become imperative, a ratemaking process which penalizes frontier exploration—in deeper waters, at greater depths, in difficult territory—becomes a national affront.

I readily admit that the present situation is one most readily remedied—and most properly remedied—by Congressional action to amend the Natural Gas Act to decontrol wellhead prices. But until Congress grasps the nettle, we must all live with the Act as written. So long as producer rates are our responsibility and our duty, let us at least do our best to make the system work. It has not worked, and it cannot work, within the framework erected by the Commission in 1965 and retained by my colleagues.

[3656]

It does no good whatsoever for a lone dissenter to say what he would do if change were within his power. The first step is for a reviewing court to recognize the inherent folly of the present structure; to recognize that consumers are being injured, not protected, by the Commission. I am wholly unpersuaded that the mind of man cannot devise a more effective, more reasonable, and more just method of regulating producer rates than perpetuated by today's opinion.

/s/ RUSH MOODY, JR.
Rush Moody, Jr.,
Commissioner

[3657]

Appendix A

PARTIES FILING PETITIONS FOR REHEARING

Producers

Amoco Production Company
Atlantic Richfield Company
Austral Oil Company Incorporated
Belco Petroleum Corporation
Edwin L. Cox
GHK Company and Gasanadarko, Ltd.
Mobil Oil Corporation
Murphy Oil Corporation
Pennzoil Company, *et al.*
The Rodman Corporation
Superior Oil Company
Tenneco Oil Company
Texasgulf, Inc.
Indicated Producers Respondents (Shell Oil Company, *et al.*)
Independent Oil & Gas Association of West Virginia
Ohio Oil And Gas Association

Pipelines

Carolina Pipeline Company
Columbia Gas System Companies
El Paso Natural Gas Company
Natural Gas Pipeline Company of America
Northern Natural Gas Company
Panhandle Eastern Pipeline Company and Trunkline Gas Company
Texas Eastern Transmission Corporation and

Transwestern Pipeline Company
Texas Gas Transmission Corporation
Transcontinental Gas Pipe Line Company
United Gas Pipeline Company
Interstate Natural Gas Association of America

Distributors

American Public Gas Association
Associated Gas Distributors
United Distribution Companies
Equitable Gas Company
Piedmont Natural Gas Company
Southern California Gas Company

[3658]

Appendix A

Governmental Agencies

State Corporation Commission of the State of Kansas
Oil Conservation Commission of the State of New Mexico
Public Service Commission of the State of New York
Oil and Gas Conservation and Commission of the State of West Virginia
Senator James G. Abourezk

Miscellaneous

General Motors Corporation

[3659]

Appendix B

PARTIES PARTICIPATING IN ORAL ARGUMENT

Indicated Producer Respondents, Shell Oil Company, *et al.*
GHK Company and Gasanadarko, Ltd.
Mobil Oil Corporation
The Rodman Corporation, *et al.*
Independent Oil & Gas Association of West Virginia
Kentucky Oil & Gas Association
Ohio Oil & Gas Association
Independent Petroleum Association of America
Interstate Natural Gas Association of America, *et al.*
Columbia Gas System
Consolidated Natural Gas System
El Paso Natural Gas Company
Northern Natural Gas Company
United Gas Pipeline Company
American Public Gas Association
Associated Gas Distributors
Brooklyn Union Gas Company
Equitable Gas Company
Southern California Gas Company, *et al.*
United Distribution Companies
Oil & Gas Conservation Commission of the State of West Virginia
Public Service Commission of the State of New York
Senator James G. Abourezk
Environmental Control Corporation
General Motors

Appendix C
Sheet 1 of 7

ESTIMATED NATIONWIDE COST OF FINDING
AND PRODUCING NON-ASSOCIATED NATURAL GAS

(Cents per Mcf at 14.73 psia)

Cost Component	1972 Data	Trended Data
Successful Wells	5.68	6.15
Recompletions & Deeper Drilling	0.20	0.20
Lease Acquisition	3.83	4.28
Other Production Facilities	1.28	1.39
Subtotal	10.99	12.02
Dry Holes	3.77	3.72
Other Exploration	2.62	2.80
Exploration Overhead	0.82	0.82
Subtotal	7.21	7.34
Operating Expense	3.10	3.10
Regulatory Expense	0.20	0.20
Net Liquid Credit	(3.89)	(3.89)
Return on Working Capital	1.14	1.25
Return on Investment	21.42	23.21
Subtotal	40.17	43.23
Royalty (16 Percent)	7.65	8.23
Total	47.82	51.46

Appendix C
Sheet 2 of 7

DERIVATION OF COST COMPONENTS

The cost components on Sheet 1 are derived as follows:

(a) The components under the Column entitled "1972 Data" with the exception of the Return on Investment and the Royalty components are taken from Column (f), Sheet 1 of 9, Schedule No. 1, Appendix C, Opinion No. 699. The Royalty and Return on Investment Components are computed on Sheet of this Appendix C.

(b) The cost components under the Column entitled "Trended Data" are derived from the following base data:

Successful Well Drilling Cost: $29.83 per foot
Dry Hole Drilling Cost : $16.69 per foot

Productivity : 485 Mcf per foot

Allocation Ratios are based upon Joint Association Survey data for 1968 through 1972.

Ratio of Lease Acquisition Costs to Successful Well Costs (1968-1972):

5739 ÷ 8327 = 0.6957

Ratio of Other Exploratory Costs to Lease Acquisition Costs (1968-1972):

3792 ÷ 5793 = 0.6546

Ratio of Exploratory Overhead to Dry Hole and Other Exploratory Costs (1968-1972):

1048 ÷ 8249 = 0.1270

Appendix C
Sheet 3 of 7

Individual Cost Components for the Trended Data are computed as follows:

Cost Component	
Successful Wells	6.15 = 29.83 ÷ 485
Recompletions & Deeper Drilling	0.20 (Opinion No. 662)
Lease Acquisition	4.28 = 6.15 x 0.6957
Other Production Facilities	1.39 = 6.15 x 0.226
Subtotal	12.02
Dry Holes	3.72 = 16.69 x 1.08 ÷ 485
Other Exploration	2.80 = 4.28 x 0.6546
Exploration Overhead	0.82 = (3.72 + 2.80) x 0.127
Subtotal	7.34
Operating Expense	3.10 (Opinion No. 662)
Regulatory Expense	0.20 (Opinion No. 662)
Net Liquid Credit	(3.89) (Opinion No. 598)
Return on Working Capital	1.25 =((7.34 x 1.336 + 3.10 x 1.689) x 0.125 + 4.28 x 1.5) x 0.15
Return on Investment	23.21 (Sheets 6-7)
Subtotal	43.23
Royalty	8.23 = 43.23 ÷ (1 - 0.16)
Total	51.46

Appendix C
Sheet 4 of 7

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY

Part 1: Computations for 1972 Data

Component	Year	Value	Tax Credit	Net Investment	Present Value (Time = 0.5)
Other Exploration	-3	2.62	1.194	1.426	2.169
Exploration Overhead	-3	0.82	0.3739	0.446	0.678
Lease Acquisition	-2	3.83	a/	3.83	5.065
Dry Holes	-1	3.77	1.8069	1.9604	2.254
Successful Well & Recompletions	-1	5.88	1.9757	3.9043	4.490
Other Production Facilities	-1	1.28	0	1.28	1.472
Lease Acquisition Tax Credit	-1		1.3788	-1.3788	-1.586
Total		18.20	6.372		14.543

a/ The lease acquisition tax credit is taken in year -1.

Appendix C
Sheet 5 of 7

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY

Part 1: Computations for 1972 Data

Computation of Net Cash Flow

Price	X
- Royalty	-0.16X
-Operating Expense	-3.10
- Interest on Working Capital	-1.14
- Regulatory Expense	-0.20
- Tax Liability to offset Tax Credit	-6.732
+ Net Liquid Credit	+3.89
Total	0.84X - 7.282

At the midpoint of the first production year the present value of the net cash flow plus the present value of the 1.0 cents per Mcf annual escalation must equal the present value of the net investment.

From Opinion No. 699 (Appendix H, Case II and Case III)

$14.543 = ((0.84X - 7.282) \times (1/18) \times 7.047) + ((0.84/18) \times 35.829965)$

$14.543 = 0.3289X - 2.851 + 1.6702$

$X = 47.82$

Royalty $= 0.16 \times 47.82 = 7.65$

Appendix C
Sheet 6 of 7

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY

Part 2: Computations for Trended Data

Component	Year	Value	Tax Credit	Net Investment	Present Value (Time = 0.5)
Other Exploration	-3	2.80	1.2770	1.523	2.317
Exploration Overhead	-3	0.83	0.3739	0.446	0.678
Lease Acquisition	-2	4.28	a/	4.28	5.660
Dry Holes	-1	3.72	1.786	1.934	2.224
Successful Well & Recompletions	-1	6.35	2.134	4.216	4.848
Other Production Facilities	-1	1.39	0	1.39	1.599
Lease Acquisition Tax Credit	-1		1.540	-1.540	-1.771
Total		19.36	7.1109		15.555

a/ The lease acquisition tax credit is taken in year -1.

Appendix C
Sheet 7 of 7

COMPUTATION OF RETURN ON INVESTMENT AND ROYALTY

Part 2: Computations for Trended Data

Computation of Net Cash Flow

Price	X
- Royalty	-0.16X
- Operating Expense	-3.10
- Interest on Working Capital	-1.25
- Regulatory Expense	-0.20
- Tax Liability to offset Tax Credit	-7.1109
+ Net Liquid Credit	+3.89
Total	0.84X - 7.771

At the midpoint of the first production year the present value of the net cash flow plus the present value of the 1.0 cents per Mcf annual escalation must equal the present value of the net investment.

From Opinion No. 699 (Appendix H, Case II and Case III)

$15.555 = ((0.84X - 7.771) \times (1/18) \times 7.047) + ((0.84/18) \times 35.829965)$

$14.543 = 0.3289X - 3.042 + 1.6702$

$X = 51.46$

$\text{Royalty} = 0.16 \times 51.46 = 8.23$

[3718]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

PIPELINE PRODUCTION
AREA RATES

Before Commissioners: John N. Nassikas, Chairman; Albert B. Brooke, Jr., Rush Moody, Jr., William L. Springer, and Don S. Smith.

Just And Reasonable National Rates For Sales of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973	Docket No. R-389-B

ORDER CLARIFYING OPINION NO. 699-H

(Issued January 31, 1975)

El Paso Natural Gas Company on January 14, 1975, filed a request for immediate clarification of the effective date of the 35¢ per Mcf rate established for certain sales from the Rocky Mountain Area in Opinion No. 699-H, issued December 4, 1974, in the above-entitled proceeding. The effective date for any proposed increased rates filed on or before January 31, 1975, pursuant to Opinion No. 699-H for sales from the Rocky Mountain Area subject to the 35¢ per Mcf ceiling is June 21, 1974.

Northwest Pipeline Corporation (Northwest) and Consolidated Gas Supply Corporation (Consolidated) on January 2 and January 3, 1975, respectively, sought clarification with respect to the applicability of the national

rate prescribed in Opinion No. 699-H to pipeline and pipeline affiliate production. The basic purpose of including pipeline production in Opinion No. 699-H, mimeo pp. 47-50, was to permit pipelines to charge the same rate for gas produced by them from leases acquired prior to October 7, 1969, which came within the general categories covered in that opinion as they were permitted

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to charge with respect to leases acquired on or after October 7, 1969. Northwest and Consolidated contend, however, that they are entitled to higher rates than those prescribed in Opinion No. 699-H for their production in the Rocky Mountain and Appalichian Areas, respectively, from leases acquired prior to October 7, 1969. Our determination in Opinion No. 699-H does not preclude a pipeline from showing in a pipeline rate case that it is entitled to special relief from that opinion in the form of a higher rate for its own production or that of its affiliate.

The Commission orders:

(A) The effective date for any proposed increased rate filed on or before January 31, 1975, pursuant to Opinion No. 699-H for sales from the Rocky Mountain Area subject to the 35¢ per Mcf ceiling is June 21, 1974.

(B) Opinion No. 699-H does not preclude a pipeline from showing in a pipeline rate case that it is entitled to special relief from that opinion in the form of a higher rate for its own production or that of its affiliate.

By the Commission.

(S E A L)

Kenneth F. Plumb,
Secretary.

APPENDIX E

SECTIONS 4, 5, 7 AND 19 OF THE NATURAL GAS ACT OF 1938, 52 STAT 821-833, AS AMENDED 15 U.S.C. SECTIONS 717c, 717d, 717f AND 717r.

SECTIONS 4, 5, 7, AND 19 OF THE NATURAL GAS ACT OF 1938, 52 STAT 821-833, AS AMENDED 15 U.S.C. SECTIONS 717c, 717d, 717f AND 717r

15 U.S.C. § 717c.

(a) All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.

(b) No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time (not less than sixty days from June 21, 1938) and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Unless the Commission otherwise orders, no change shall be made by any natural-gas company in any such rate,

charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after thirty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the thirty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Whenever any such new schedule is filed the Commission shall have authority, either upon complaint of any State, municipality, State commission or gas distributing company, or upon its own initiative without complaint, at once, and if it so orders, without answer or formal pleading by the natural-gas company, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the natural-gas company affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect, and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded

and an order made at the expiration of the suspension period, on motion of the natural-gas company making the filing, the proposed change of rate, charge, classification, or service shall go into effect. Where increased rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission, to keep accurate accounts in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts were paid, and, upon completion of the hearing and decision, to order such natural-gas company to refund, with interest, the portion of such increased rates or charges by its decision found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the natural-gas company, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible. June 21, 1938, c. 556, § 4, 52 Stat. 822; May 21, 1962, Pub.L. 87-454, 76 Stat. 72.

15 U.S.C. § 717d.

(a) Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall

determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: *Provided, however,* That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates.

(b) The Commission upon its own motion, or upon the request of any State commission, whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transportation of natural gas by a natural-gas company in cases where the Commission has no authority to establish a rate governing the transportation or sale of such natural gas. June 21, 1938, c. 556, § 5, 52 Stat. 823.

15 U.S.C. § 717f.

(a) Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon

such natural-gas company thereby: *Provided,* That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: *Provided, however,* That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings,

if application for such certificate is made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: *Provided, however,* That the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(d) Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Except in the cases governed by the provisos contained in subsection (c) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission

thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) The Commission, after a hearing had upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization.

(g) Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

(h) When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may

be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the property is situated: *Provided*, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds $3,000. June 21, 1938, c. 556, § 7, 52 Stat. 824; Feb. 7, 1942, c. 49, 56 Stat. 83; July 25, 1947, c. 333, 61 Stat. 459.

15 U.S.C. § 717r.

(a) Any person, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this chapter to which such person, State, municipality, or State commission is a party may apply for a rehearing within thirty days after the issuance of such order. The application for rehearing shall set forth specifically the ground or grounds upon which such application is based. Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing. Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied. No proceeding to review any order of the Commission shall be brought by any person unless such person shall have made application to the Commission for a rehearing thereon. Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b) of this section, the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.

(b) Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the court of appeals of the United States for any circuit wherein the natural-gas company to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of Title 28. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may

seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings, which if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in sections 346 and 347 of Title 28.

(c) The filing of an application for rehearing under subsection (a) of this section shall not, unless specifically ordered by the Commission, operate as a stay of the Commission's order. The commencement of proceedings under subsection (b) of this section shall not, unless specifically ordered by the court, operate as a stay of the Commission's order. June 21, 1938, c. 556, § 19, 52 Stat. 831; June 25, 1948, c. 646, § 32(a), 62 Stat. 991; May 24, 1949, c. 139, § 127, 63 Stat. 107; Aug. 28, 1958, Pub.L. 85-791, § 19, 72 Stat. 947.